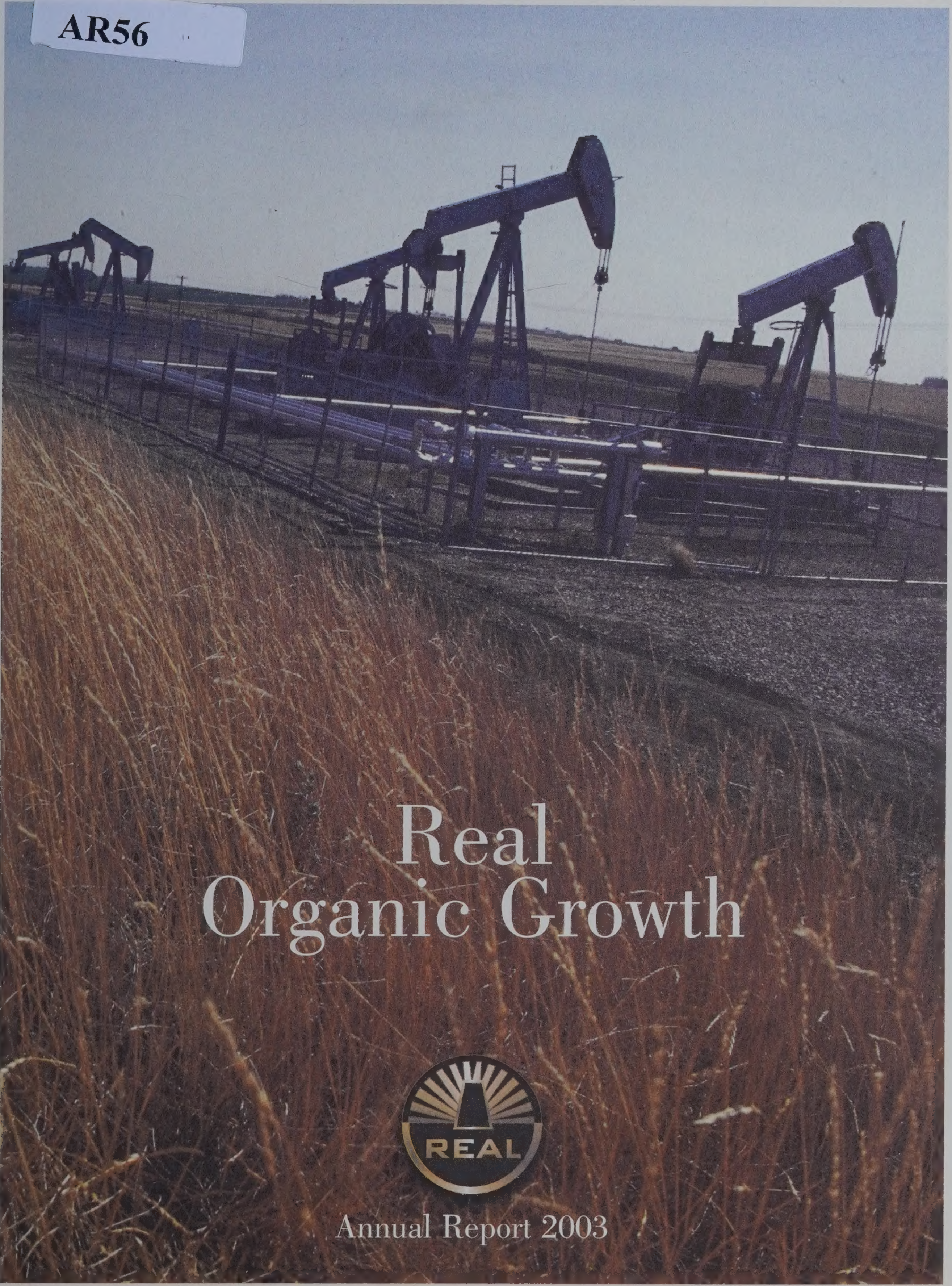


# Real Organic Growth

REAL

Annual Report 2003

# Real Resources Inc. is a Calgary based oil and gas company active in the exploration, development and production of crude oil and natural gas in Western Canada. The Company has grown through exploration, development and strategic acquisitions.

**TABLE OF CONTENTS**

# Highlights

| *($ thousands, except where noted)* | 2003 | 2002 | % change |
|---|---|---|---|
| **Financial** | | | |
| Production revenue | 72,172 | 52,554 | 37 |
| Cash flow from operations | 36,142 | 26,829 | 35 |
| Per share *(basic)* * | $ 1.58 | $ 1.36 | 16 |
| Per share *(diluted)* * | $ 1.56 | $ 1.34 | 16 |
| Net earnings | 15,383 | 5,907 | 160 |
| Per share *(basic)* | $ 0.67 | $ 0.30 | 123 |
| Per share *(diluted)* | $ 0.66 | $ 0.29 | 128 |
| Long-term debt *(net)* | 67,697 | 56,570 | 20 |
| Total assets | 205,105 | 163,346 | 26 |
| Shareholders' equity | 89,618 | 61,624 | 45 |
| Net capital expenditures | 59,499 | 54,270 | 10 |
| Average common shares outstanding *(000s)* | 22,804 | 19,716 | 16 |
| **Operating** | | | |
| Working interest production | | | |
| Crude oil and liquids *(bbls/d)* | 3,352 | 3,248 | 3 |
| Natural gas *(mcf/d)* | 12,833 | 9,148 | 40 |
| Total oil equivalent *(boe/d)* | 5,491 | 4,772 | 15 |
| Average prices | | | |
| Oil *($/bbl)* | 35.65 | 33.73 | 6 |
| Gas *($/mcf)* | 5.96 | 3.73 | 60 |
| Cash flow netback (before abandonment) *($/boe)* | 18.12 | 15.44 | 17 |
| Operating costs *($/boe)* | 7.52 | 6.03 | 25 |
| General and administrative *($/boe)* | 1.59 | 1.64 | (3) |
| Wells drilled | | | |
| Gross | 91 | 114 | (20) |
| Net | 78.1 | 99.8 | (22) |

* Cash flow from operations per share is a non-GAAP term that represents net earnings measures adjusted for non-cash items. The Company evaluates its performance based on net earnings and cash flow from operations. The Company considers cash flow a key measure as it demonstrates the Company's ability to generate cash flow necessary to fund future growth through capital investment and to repay debt.

**ABBREVIATIONS**

| | |
|---|---|
| **bbls** | barrels |
| **mbbls** | thousand barrels |
| **bbls/d** | barrels of oil per day |
| **mcf** | thousand cubic feet |
| **mmcf** | million cubic feet |
| **mcf/d** | thousand cubic feet per day |
| **boe** | barrel of oil equivalent where natural gas is equated to oil using 6 mcf = 1 barrel of oil |
| **mboe** | thousand barrels of oil equivalent |
| **boe/d** | barrel of oil equivalent per day |
| **NGL** | natural gas liquids |

# Message to our Shareholders
## IN CONVERSATION WITH LOWELL JACKSON

### *How would you describe Real's performance in 2003?*

In 2003, we achieved double-digit growth in land, production and reserves and posted record financial results for the fifth consecutive year. We made significant strides toward our goal of growing production to more than 10,000 boe per day within two to three years. We added significant natural gas volumes, moving us closer to an even split between oil and natural gas. Overall, it was a year of solid, organic growth.

### *What were some of the highlights?*

We were one of the industry's most active drillers in 2003. Our 91-well program resulted in the discovery of 24 new oil/gas pools within our core areas. Daily production increased by 15 percent in 2003 and natural gas production climbed by 40 percent, signaling our success in bringing more of our natural gas reserves into production.

On a boe basis, fourth quarter volumes were 48 percent natural gas. We are particularly pleased with this result, as achieving a balance between oil and gas was a key objective for us.

Our reserve growth in 2003 was impressive and was realized entirely through the drill bit. Total reserve additions replaced 418 percent of production and resulted in a 34 percent reserve growth (17 percent per share). Natural gas reserves increased 54 percent and now account for over half of our reserves. On a total proved plus probable basis, our finding and development costs were $7.10 per boe, excluding future development costs. Our reserve life index using average 2003 production increased to 12.6 years. As our practices for booking reserves are conservative, the new stricter industry-wide standards had no adverse effect on our reserve reporting.

We spent a record $14.3 million on land and seismic. Our total undeveloped land holdings grew to nearly 240,000 net acres, a 25 percent increase from last year.

We also established Central Alberta as a new core area. In just over two years, we have accumulated a land position of 21 sections in this tightly held area and have built production to more than 1,000 boe per day. This is similar to the way we managed the Scandia prospect, taking production from zero to 2,000 boe per day in three years, and it illustrates the success of our grass-roots approach to exploration.

### *Were there any disappointments in 2003?*

We experienced significant delays in bringing on new gas production at Scandia due to lack of available processing capacity in the area, which caused us to miss our production targets. This was certainly a hiccup in our growth plans in 2003, but this problem is now behind us.

Most of our Scandia gas is now on production. Fourth quarter volumes averaged 10.2 million cubic feet per day (net), versus 0.9 million cubic feet per day in the fourth quarter of 2002. Including our oil volumes, Scandia production averaged 2,000 boe per day in the fourth quarter, a tenfold increase from a year ago.

### *What are your current plans for Scandia?*

Scandia became our top natural gas property in 2003, in terms of reserves and production. Our success has attracted more industry competition to the area. However, we have a sizable foothold with a land position of 53 sections with an average working interest of 90 percent, supported by 29 square miles of proprietary 3-D seismic. Facility expansions currently underway will enable us to increase our total deliverability to 18.0 million cubic feet per day by mid 2004, which is sufficient for our current plans.

We see significant potential to add reserves and production in this area. We have a large inventory of drill-ready natural gas prospects, with multi-zone potential. In addition, we have identified a number of Arcs oil prospects. We plan to invest 20 percent of our capital in Scandia in 2004.

## *How will you create value going forward?*

We continue to follow the course we embarked on in 1997, with a focus on long-term value creation which started in southeast Saskatchewan, in the lower risk part of the basin. Over the past seven years, we have slowly moved west in search of deeper targets with longer reserve life and higher productivity. Our Southeast Saskatchewan and East Central Alberta core areas are now in harvest mode. Our current development focus is in Southern Alberta, while West Central Alberta represents our future growth.

Our reserves growth in 2003 represents prospects that we initiated five years ago. The growth we are expecting to see in three to four years will come from prospects we are developing today. We have not run out of ideas or opportunities as our prospect generation continues to be fruitful, giving us at least a two-year inventory of drilling locations.

Our full-cycle exploration approach should continue to deliver steady growth that is attractive to a long-term investor.

## *What is your current outlook on commodity prices and industry activity levels?*

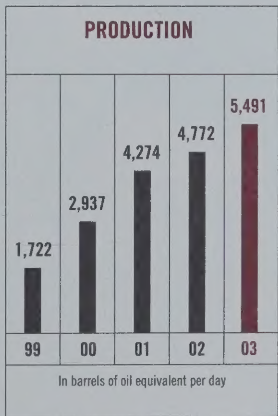
Crude oil and natural gas prices along with equity markets remain robust and continue to perform above market expectations, creating a positive yet competitive environment.

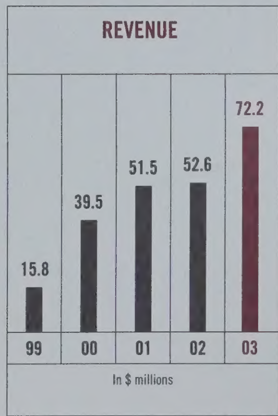
In 2003, world oil prices strengthened but reacted with volatility to global events throughout the year with prices remaining at the high end of the historical range. Unpredictability is expected to continue in 2004, reflecting continuing supply and demand imbalances, including uncertainty about increased supply from Iraq and increased demand from China.

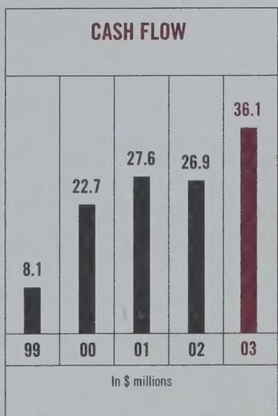
Strong demand for natural gas in North America kept prices firm throughout 2003. Although some seasonal fluctuation is anticipated, natural gas prices are expected to remain strong in 2004.

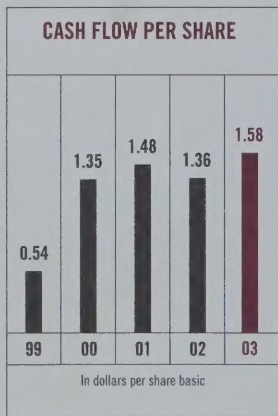
Some of the benefit of higher commodity prices in 2003 has been offset by our stronger Canadian dollar, which rose 20 percent against its U.S. counterpart. The Canadian dollar is expected to remain strong in 2004.

As is our style, we have maintained a conservative approach to price forecasting in our planning. For 2004, we are using an average price of U.S.$29.00 per barrel (WTI) for oil and Cdn.$6.50 per mcf (AECO "C") for natural gas, and a Canadian/U.S. dollar exchange rate of $0.77. Through our risk management program, we have locked in minimum prices of U.S.$24.00 per barrel (WTI) for oil and $4.60 per mcf for gas on approximately 65 percent of our production for 2004. This program is designed to protect our cash flow by establishing a minimum price should commodity prices fall without giving up much of the price upside.



**Lowell E. Jackson**, P.Eng.
President & Chief Executive Officer

**Pamela J. Orr**, CA, CFA
Vice President Finance
& Chief Financial Officer

**Frank P. Muller**, P.Geol.
Vice President Exploration

**Ken P. Murphy**, P.Land
Executive Vice President

## OUR VISION

*Our goal is to create growth and value for our shareholders over the long term. Our objective is to grow production to more than 10,000 boe per day within two to three years, split evenly between crude oil and natural gas. Our exploration and development strategy remains consistent and has proven successful. To complement internal prospect generation, we will continue to exploit opportunities to add strategic corporate and asset acquisitions in core areas. We manage and take advantage of commodity price cycles through a conservative hedging program and a flexible, counter-cyclical approach to project economics.*

## *What are your goals for 2004?*

Our capital budget for 2004 is $65 million. With our current plans, we expect annual production will average 7,200 boe per day. That's a 30 percent increase over 2003 and it's a target we have confidence in. Our fourth quarter volumes in 2003 were in excess of 6,500 boe per day, and we have about 400 boe per day, in Central Alberta awaiting tie-ins in the first quarter of 2004. We plan to drill 127 wells, including 85 development locations, in 2004. Our target is to maintain a balance of oil and natural gas on both a reserves and production basis. Therefore, natural gas projects will continue to be a focus in 2004 and will make up 60 percent of our capital program.

We are continually working towards lowering our operating costs. Oil production typically has higher operating costs due to electricity for pumping, trucking costs, and downhole maintenance. With a higher proportion of our production now coming from natural gas, our cost structure should improve. In addition, costs per boe should come down as our production volumes increase.

The Scandia production delays affected our cash flow, and we ended the year with higher levels of debt than planned. It is a priority for us to reduce our debt to cash flow ratio. Strong commodity prices and higher volumes will result in increased cash flow in 2004. We will continue to exercise capital discipline and protect the downside through hedging.

In addition, we recently announced a $27.3 million common share issue (4.3 million common shares at $6.35 per share), which is scheduled to close on March 30, 2004. Proceeds from this offering will be used to fund our capital program. Upon completion of this financing our debt to cash flow will be approximately 1:1, which is well below our objective.

## *Do you have any closing comments?*

I'd like to take this opportunity to recognize our staff who have worked as a unified team in attaining our corporate objectives. They have delivered outstanding results for our shareholders for the fifth straight year. Though small in numbers, I believe their talents and passion for the work we do are unmatched in the industry.

I would also like to thank our Board of Directors for their valued counsel and guidance throughout the year. Most importantly I thank you, my fellow shareholders, for your confidence in the future of Real. We continue to work hard to earn your ongoing support.

On behalf of the Board of Directors,

**Lowell E. Jackson**, **P. Eng.**
President & Chief Executive Officer
March 18, 2004

# Statistical Review

## RESERVES RECONCILIATION[1][2][3]

### RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE

| Forecast prices and costs | Light and medium crude oil | Natural gas | Natural gas liquids | Boe |
|---|---|---|---|---|
| | *(mbbls)* | *(mmcf)* | *(mbbls)* | *(mboe)* |
| **Total proved** | | | | |
| Opening balance | 7,906 | 43,662 | 625 | 15,808 |
| Drilling | 1,855 | 26,371 | 254 | 6,504 |
| Revisions | (377) | (4,473) | (253) | (1,375) |
| Acquisitions | – | – | – | – |
| Dispositions | – | (676) | – | (113) |
| Production | (1,172) | (4,684) | (51) | (2,004) |
| **Closing balance** | **8,212** | **60,200** | **575** | **18,820** |
| **Probable** | | | | |
| Opening balance | 1,371 | 9,642 | 137 | 3,115 |
| Drilling | 835 | 6,846 | 59 | 2,035 |
| Revisions | 319 | 6,177 | 29 | 1,377 |
| Acquisitions | – | – | – | – |
| Dispositions | – | (267) | – | (44) |
| Production | – | – | – | – |
| **Closing balance** | **2,525** | **22,398** | **225** | **6,483** |
| **Proved plus probable** | | | | |
| Opening balance | 9,277 | 53,304 | 762 | 18,923 |
| Drilling | 2,690 | 33,217 | 313 | 8,539 |
| Revisions | (58) | 1,704 | (224) | 2 |
| Acquisitions | – | – | – | – |
| Dispositions | – | (943) | – | (157) |
| Production | (1,172) | (4,684) | (51) | (2,004) |
| **Closing balance** | **10,737** | **82,598** | **800** | **25,303** |

(1) May not add due to rounding.

(2) Gross Reserves represent the Company's interest before deducting royalties and without including any royalty interest of the Company.

(3) Opening balance is based on 50 percent risked probable reserves.

## RESERVES BY PROPERTY[1][2]

| (at December 31, 2003) | Light and medium crude oil (mbbls) | Natural gas (mmcf) | Natural gas liquids (mbbls) | Boe (mboe) |
|---|---|---|---|---|
| **Total proved** | | | | |
| Scandia | 329 | 20,329 | 158 | 3,875 |
| Hays/Enchant | 3,082 | 2,585 | 127 | 3,640 |
| Atlee/Buffalo | – | 12,761 | – | 2,127 |
| Ferrybank | 513 | 4,297 | 27 | 1,256 |
| West Provost | 189 | 4,307 | 11 | 917 |
| Consort | 816 | 72 | 1 | 829 |
| Neutral Hills | 727 | 597 | – | 827 |
| Sounding Lake | 792 | 97 | 6 | 814 |
| Rocanville | 779 | – | – | 779 |
| Alida West | 652 | 321 | – | 705 |
| Westerose | – | 2,994 | 172 | 671 |
| Two Creek | – | 1,994 | 8 | 341 |
| Windfall | – | 1,347 | – | 225 |
| Other properties | 333 | 8,499 | 65 | 1,814 |
| **Total** | **8,212** | **60,200** | **575** | **18,820** |
| **Probable** | | | | |
| Scandia | 179 | 8,460 | 51 | 1,640 |
| Hays/Enchant | 1,138 | 617 | 30 | 1,271 |
| Atlee/Buffalo | – | 3,603 | – | 600 |
| Ferrybank | 93 | 2,346 | 32 | 516 |
| West Provost | 130 | 1,309 | 4 | 353 |
| Consort | 135 | 13 | – | 137 |
| Neutral Hills | 185 | 57 | – | 194 |
| Sounding Lake | 294 | 43 | 3 | 304 |
| Rocanville | 216 | – | – | 216 |
| Alida West | 103 | 50 | – | 112 |
| Westerose | – | 294 | 19 | 68 |
| Two Creek | – | 295 | 2 | 50 |
| Windfall | – | 651 | – | 108 |
| Other properties | 52 | 4,660 | 84 | 914 |
| **Total** | **2,525** | **22,398** | **225** | **6,483** |
| **Proved plus probable** | | | | |
| Scandia | 508 | 28,789 | 209 | 5,515 |
| Hays/Enchant | 4,220 | 3,202 | 157 | 4,911 |
| Atlee/Buffalo | – | 16,364 | – | 2,727 |
| Ferrybank | 606 | 6,643 | 59 | 1,772 |
| West Provost | 319 | 5,616 | 15 | 1,270 |
| Consort | 951 | 85 | 1 | 966 |
| Neutral Hills | 912 | 654 | – | 1,021 |
| Sounding Lake | 1,086 | 140 | 9 | 1,118 |
| Rocanville | 995 | – | – | 995 |
| Alida West | 755 | 371 | – | 817 |
| Westerose | – | 3,288 | 191 | 739 |
| Two Creek | – | 2,289 | 10 | 391 |
| Windfall | – | 1,998 | – | 333 |
| Other properties | 385 | 13,159 | 149 | 2,728 |
| **Total** | **10,737** | **82,598** | **800** | **25,303** |

(1) May not add due to rounding.

(2) Gross Reserves represent the Company's interest before deducting royalties and without including any royalty interest of the Company.

## SUMMARY OF OIL AND GAS RESERVES FORECASTED PRICES AND COSTS [1][2]

| Company interest | Light and medium crude oil | Natural gas | Natural gas liquids | 2003 Boe | 2002 Boe [3] |
|---|---|---|---|---|---|
| | *(mbbls)* | *(mmcf)* | *(mbbls)* | *(mboe)* | *(mboe)* |
| Proved | | | | | |
| Developed producing | 7,031 | 37,710 | 447 | 13,763 | 12,460 |
| Developed non-producing | 169 | 13,681 | 95 | 2,544 | 1,738 |
| Undeveloped | 1,012 | 8,809 | 33 | 2,513 | 1,610 |
| Total proved | 8,212 | 60,200 | 575 | 18,820 | 15,808 |
| Probable | 2,525 | 22,398 | 225 | 6,483 | 3,115 |
| **Total proved plus probable** | **10,737** | **82,598** | **800** | **25,303** | **18,923** |

(1) May not add due to rounding.
(2) Gross Reserves represent the Company's interest before deducting royalties and without including any royalty interest of the Company.
(3) Represents proved plus 50 percent risked probable reserves.

## NET PRESENT VALUE OF RESERVES FORECASTED PRICES AND COSTS *(including ARTC and before income taxes)* [1][2]

| *($ thousands)* | Undiscounted | Discounted at 5% | Discounted at 10% | Discounted at 15% | Discounted at 20% |
|---|---|---|---|---|---|
| Proved | | | | | |
| Developed producing | 181,493 | 149,336 | 128,116 | 113,140 | 101,983 |
| Developed non-producing | 34,071 | 26,441 | 21,633 | 18,281 | 15,802 |
| Undeveloped | 29,521 | 16,124 | 9,673 | 6,012 | 3,693 |
| Total proved | 245,085 | 191,901 | 159,422 | 137,433 | 121,478 |
| Probable | 84,639 | 54,047 | 38,770 | 29,736 | 23,790 |
| **Total proved plus probable** | **329,724** | **245,948** | **198,192** | **167,169** | **145,268** |

(1) May not add due to rounding.
(2) As required by NI 51-101, undiscounted well abandonment costs of $11.4 million for total proved reserves and $13.0 million for total proved plus probable reserves are included in the Net Present Value determination.

## PRICING FORECAST [1]

| | West Texas Intermediate U.S.$/bbl | | | Edmonton Reference Price Cdn.$/bbl | | | Natural Gas Price AECO "C" Cdn.$/mcf | | |
|---|---|---|---|---|---|---|---|---|---|
| December 31 | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 |
| 2002 | – | – | 21.00 | – | – | 32.31 | – | – | 3.76 |
| 2003 | – | 26.00 | 21.50 | – | 38.96 | 32.55 | – | 5.60 | 4.30 |
| 2004 | 29.00 | 24.00 | 21.93 | 37.61 | 35.86 | 32.68 | 6.00 | 5.20 | 4.43 |
| 2005 | 26.50 | 22.50 | 22.37 | 34.25 | 33.53 | 33.33 | 5.31 | 4.88 | 4.50 |
| 2006 | 25.50 | 22.95 | 22.82 | 32.90 | 34.20 | 34.00 | 4.83 | 4.94 | 4.56 |
| 2007 | 25.00 | 23.41 | 23.27 | 32.21 | 34.89 | 34.68 | 4.87 | 5.00 | 4.65 |
| 2008 | 25.50 | 23.88 | 23.74 | 32.85 | 35.59 | 35.37 | 4.92 | 5.06 | 4.74 |
| 2009 | 26.01 | 24.35 | 24.21 | 33.51 | 36.30 | 36.08 | 4.96 | 5.12 | 4.84 |
| 2010 | 26.53 | 24.84 | 24.70 | 34.18 | 37.02 | 36.80 | 5.01 | 5.18 | 4.93 |
| 2011 | 27.06 | 25.34 | 25.19 | 34.86 | 37.76 | 37.54 | 5.05 | 5.24 | 5.03 |
| 2012 | 27.60 | 25.85 | 25.69 | 35.56 | 38.52 | 38.29 | 5.15 | 5.30 | 5.13 |
| Thereafter (per year) | +2.0% | +2.0% | +2.0% | +2.0% | +2.0% | +2.0% | +2.0% | +2.0% | +2.0% |

(1) Utilizing Paddock Lindstrom & Associates Ltd. January 1, 2004 price forecast.

## NET PRESENT VALUE OF RESERVES
## CONSTANT PRICES AND COSTS *(including ARTC and before income taxes)* (1)(2)

| *($ thousands)* | Undiscounted | Discounted at 5% | Discounted at 10% | Discounted at 15% | Discounted at 20% |
|---|---|---|---|---|---|
| Proved | | | | | |
| Developed producing | 256,565 | 202,798 | 169,440 | 146,706 | 130,169 |
| Developed non-producing | 47,021 | 36,155 | 29,322 | 24,575 | 21,082 |
| Undeveloped | 41,842 | 23,481 | 14,862 | 10,010 | 6,934 |
| Total proved | 345,428 | 262,434 | 213,623 | 181,291 | 158,185 |
| Probable | 117,594 | 75,116 | 54,044 | 41,559 | 33,323 |
| **Total proved plus probable** | **463,022** | **337,549** | **267,668** | **222,850** | **191,508** |

(1) May not add due to rounding.
(2) Price assumptions: $40.92 Cdn.$/bbl Edmonton Reference Price and $6.08 Cdn.$/mcf AECO "C".

## PRODUCTION BY AREA

| | 2003 | 2002 | 2001 |
|---|---|---|---|
| **Crude oil and NGLs** *(bbl/d)* | | | |
| Hays/Enchant | 971 | 542 | 425 |
| Neutral Hills | 719 | 1,141 | 290 |
| Consort | 444 | 63 | – |
| Sounding Lake | 350 | 469 | 578 |
| Alida | 222 | 328 | 501 |
| Rocanville | 147 | 159 | 171 |
| West Provost | 92 | 93 | 94 |
| Evi | – | 154 | 173 |
| Minor properties | 407 | 299 | 371 |
| **Total** | 3,352 | 3,248 | 2,603 |
| **Natural gas** *(mcf/d)* | | | |
| Scandia | 4,725 | 934 | 1,138 |
| Atlee/Buffalo | 1,879 | 1,884 | 1,825 |
| West Provost | 1,456 | 1,304 | 1,168 |
| Hays/Enchant | 966 | 670 | 264 |
| Ricinus | 904 | 1,072 | 1,422 |
| Ferrybank | 691 | – | – |
| Westerose | 671 | 759 | 659 |
| Virginia Hills | 296 | 339 | 815 |
| Nelson Lake | 131 | 427 | 889 |
| Prairie River | 76 | 885 | 406 |
| Minor properties | 1,038 | 874 | 1,439 |
| **Total** | 12,833 | 9,148 | 10,025 |

## ACREAGE SUMMARY

| December 31, 2003 *(acres)* | Total Gross | Total Net | Undeveloped Gross | Undeveloped Net | Fair market value* |
|---|---|---|---|---|---|
| Alberta | 482,097 | 318,283 | 328,726 | 231,982 | $ 19,053,635 |
| Saskatchewan | 16,314 | 9,626 | 14,007 | 7,935 | 256,405 |
| **Total** | 498,411 | 327,909 | 342,733 | 239,917 | $ 19,310,040 |

* Seaton-Jordan & Associates Ltd. – Undeveloped Lands Only.

## DRILLING ACTIVITY

| | 2003 | | 2002 | | 2001 | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| **Exploratory wells** | | | | | | |
| Oil | 4 | 4.0 | 3 | 2.5 | 2 | 2.0 |
| Gas | 14 | 11.8 | 10 | 8.5 | 14 | 9.9 |
| Dry | 12 | 11.2 | 12 | 7.3 | 16 | 7.2 |
| **Subtotal** | 30 | 27.0 | 25 | 18.3 | 32 | 19.1 |
| Success rate *(%)* | 60 | 59 | 52 | 60 | 50 | 62 |
| Average working interest *(%)* | – | 90 | – | 73 | – | 68 |
| Operated wells | 27 | – | 18 | – | 20 | – |
| **Development wells** | | | | | | |
| Oil | 29 | 27.4 | 45 | 38.9 | 31 | 18.7 |
| Gas | 27 | 18.7 | 36 | 35.6 | 21 | 14.0 |
| Dry | 5 | 5.0 | 8 | 7.0 | 2 | 1.4 |
| **Subtotal** | 61 | 51.1 | 89 | 81.5 | 54 | 34.1 |
| Success rate *(%)* | 92 | 90 | 91 | 91 | 96 | 96 |
| Average working interest *(%)* | – | 84 | – | 91 | – | 64 |
| Operated wells | 49 | – | 87 | – | 31 | – |
| **Total wells** | | | | | | |
| Oil | 33 | 31.4 | 48 | 41.4 | 33 | 20.7 |
| Gas | 41 | 30.5 | 46 | 44.1 | 35 | 23.9 |
| Dry | 17 | 16.2 | 20 | 14.3 | 18 | 8.6 |
| **Total** | 91 | 78.1 | 114 | 99.8 | 86 | 53.2 |
| Success rate *(%)* | 81 | 79 | 82 | 86 | 79 | 84 |
| Average working interest *(%)* | – | 86 | – | 87 | – | 62 |
| Operated wells | 76 | – | 105 | – | 51 | – |

## FINDING AND ON-STREAM COSTS[1]

| | 2003 | 2002 [2] | 2001 [2] |
|---|---|---|---|
| **Finding costs** *($ thousands)* | | | |
| Land | 9,143 | 4,408 | 3,170 |
| Seismic | 5,159 | 3,270 | 1,883 |
| Drilling and completion | 31,885 | 25,386 | 19,558 |
| Acquisitions *(net of dispositions)* | (104) | 13,087 | 2,331 |
| Total finding costs | 46,083 | 46,151 | 26,942 |
| Facilities | 13,416 | 8,119 | 7,768 |
| Total on-stream costs | 59,499 | 54,270 | 34,710 |
| **Reserve additions** *(mboe)(including acquisitions, dispositions and revisions)* | | | |
| Proved | 5,016 | 5,761 | 1,820 |
| Proved plus probable | 8,384 | 6,481 | 2,077 |
| **Finding cost per unit** *($/boe)* | | | |
| Proved | 9.19 | 8.01 | 14.80 |
| Proved plus probable | 5.50 | 7.12 | 12.97 |
| **On-stream** *($/boe)* | | | |
| Proved | 11.86 | 9.42 | 19.07 |
| Proved plus probable | 7.10 | 8.37 | 16.71 |
| **Operating netback** *($/boe)* | 20.97 | 18.34 | 20.87 |
| **Recycle ratio** | | | |
| Proved | 1.77 | 1.95 | 1.09 |
| Proved plus probable | 2.95 | 2.19 | 1.25 |

| | 3-year average |
|---|---|
| **Finding costs** *($ thousands)* | |
| Land | 5,574 |
| Seismic | 3,437 |
| Drilling and completion | 25,610 |
| Acquisitions *(net of dispositions)* | 5,105 |
| Total finding costs | 39,726 |
| Facilities | 9,768 |
| Total on-stream costs | 49,494 |
| **Reserve additions** *(mboe)(including acquisitions, dispositions and revisions)* | |
| Proved | 4,199 |
| Proved plus probable | 5,648 |
| **Finding cost per unit** *($/boe)* | |
| Proved | 9.46 |
| Proved plus probable | 7.03 |
| **On-stream** *($/boe)* | |
| Proved | 11.79 |
| Proved plus probable | 8.76 |
| **Operating netback** *($/boe)* | 20.06 |
| **Recycle ratio** | |
| Proved | 1.70 |
| Proved plus probable | 2.29 |

(1) Excludes the net increase (decrease) in future development costs on proved reserves of $8.5 million, ($1.1) million and $4.2 million in 2003, 2002 and 2001 respectively; on proved plus probable reserves of $10.8 million, ($0.5) million and $4.4 million in 2003, 2002 and 2001 respectively.

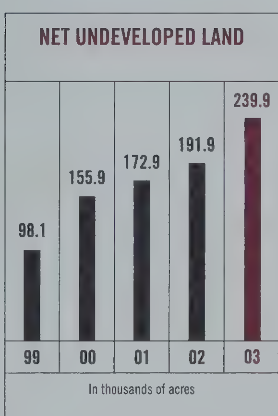
(2) Represents proved plus 50 percent risked probable reserves.

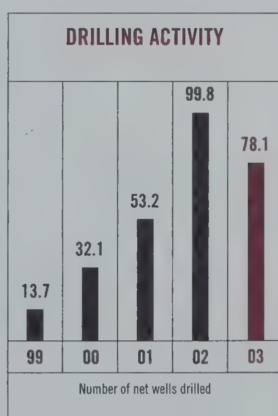
## RESERVE LIFE INDEX

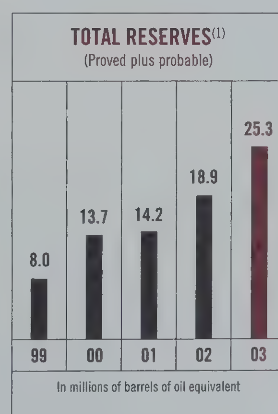
The Company's reserve life index using annualized fourth quarter production is 7.8 years for proven boe reserves compared to 9.4 years in 2002 and 10.5 years for proven plus probable boe reserves compared to 11.2 years in 2002. Reserve life calculated using annualized fourth quarter production may be more reflective of reserve life due to the active capital program and the level of new production added during the fourth quarter.

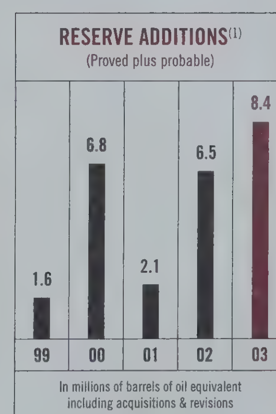
| | 2003 Using annualized Q4 production | 2003 Using average production | 2002 [1] Using annualized Q4 production | 2002 [1] Using average production | 2001 [1] Using average production |
|---|---|---|---|---|---|
| Boe | | | | | |
| Production *(mboe)* | 2,420 | 2,004 | 1,686 | 1,742 | 1,560 |
| Proved reserves *(mboe)* | 18,820 | 18,820 | 15,808 | 15,808 | 11,793 |
| Proved reserve life index *(years)* | 7.8 | 9.4 | 9.4 | 9.1 | 7.6 |
| Proved plus probable reserves *(mboe)* | 25,303 | 25,303 | 18,923 | 18,923 | 14,188 |
| Proved plus probable reserve life index *(years)* | 10.5 | 12.6 | 11.2 | 10.8 | 9.1 |

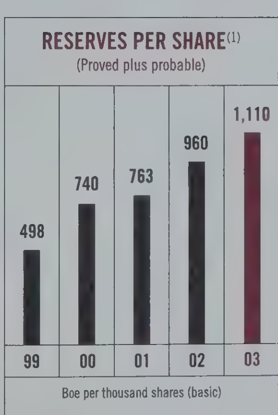
(1) Represents proved plus 50 percent risked probable reserves.

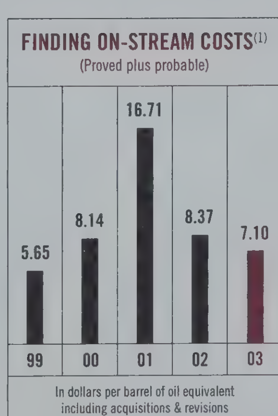


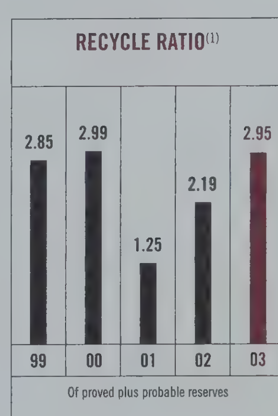



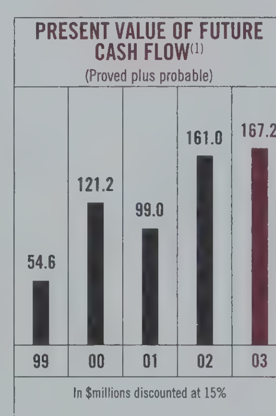




(1) Represents proved plus 50 percent risked probable reserves for 2002 and prior.

# Review of Operations

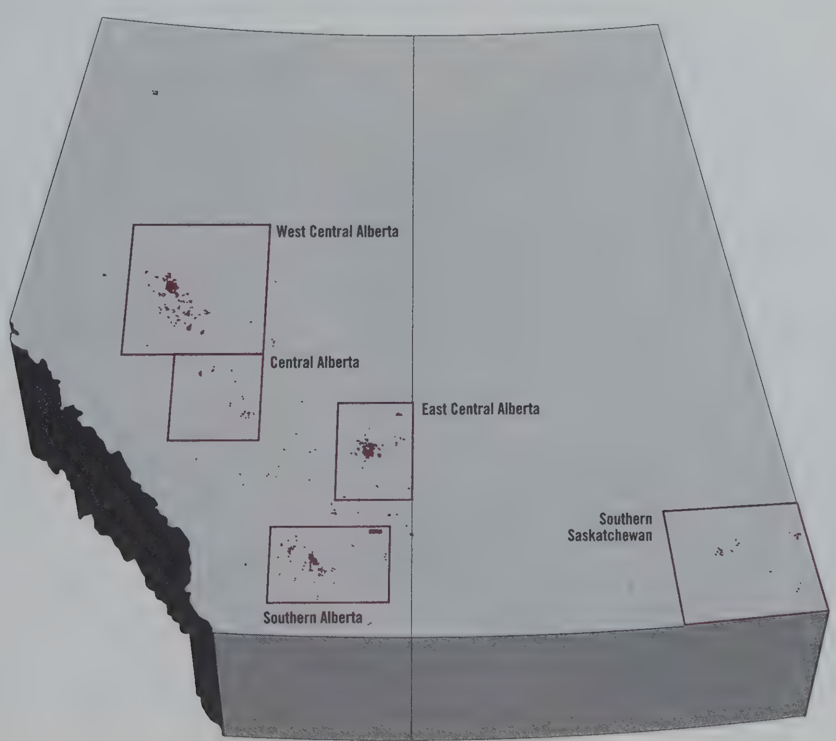
In 2003, we increased total reserves by 34 percent and production by 15 percent in our core areas entirely through the drill bit. This organic growth illustrates the success of our full-cycle exploration and development strategy.

Southern Alberta, which includes Scandia, Hays and Enchant, became our top core area in 2003. In West Central Alberta, our exploration program yielded moderate growth, and we also established Central Alberta as a new core area. Meanwhile, properties in East Central Alberta have come off flush production levels and the emphasis is now on maintaining current rates. Capital spending was minimal in Southeast Saskatchewan, but this area remains attractive because it contains our highest netback properties.

Our exploration and development momentum continued through 2003. We held our position as one of the top 25 most active drillers in Alberta. We drilled 91 wells with an average working interest of 86 percent and maintained an 81 percent success rate. We continued to emphasize hands-on management, operating 76 of the 91 wells. Development drilling represented 67 percent of our activity, while exploration represented 33 percent. We consider this a prudent balance to fuel our near-term as well as long-term growth.

In anticipation of sustained strength in natural gas markets, we increased our exposure to gas exploration and development with 41 successful gas wells. Our $59.5 million capital program resulted in proved plus probable reserve additions of 34.0 billion cubic feet of natural gas and 2.7 million barrels of oil and natural gas liquids.

We continue to consolidate our land position within our core areas. In 2003, our net undeveloped land holdings grew by 25 percent. Most of our land purchases were concentrated in our core areas and we were successful in our objective to increase our average working interest, which went from 59 percent to 71 percent.



# Southern Alberta

In 2003, we accelerated our exploration and development program in Southern Alberta, directing 42 percent of our capital program to this area. We drilled 39 wells, including 10 exploration wells.

## SCANDIA

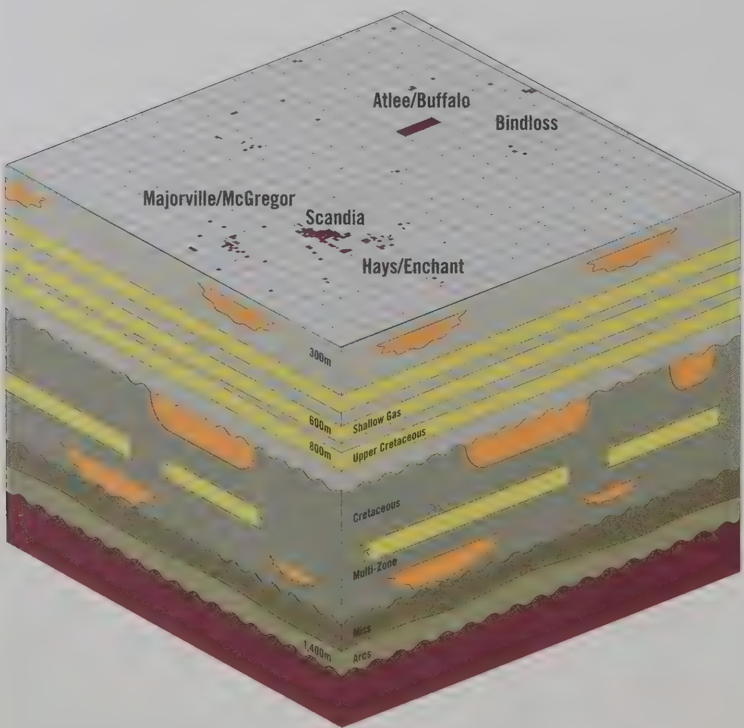
On October 3, 2003, the Scandia property emerged as our top natural gas producing property as gas commenced production through the Hays Gas Plant. Current production is 10.5 million cubic feet per day (10.2 net). Through Crown sales and selective acquisitions, we have built a land position of 53 sections with an average working interest of 90 percent. To year end 2003, we have amassed 29 square miles of proprietary 3-D seismic over the area.

At Scandia, we drilled eight exploratory tests, resulting in seven multi-zone gas discoveries (5.8 net) and one (1.0 net) dry hole. In addition, we drilled 10 development wells resulting in 10 (7.7 net) multi-zone gas wells. We are now producing natural gas from five Cretaceous formations. We have also identified five additional gas prone Cretaceous formations on the Scandia prospect.

Successful Cretaceous natural gas drilling has continued into the first quarter of 2004. Our plans for 2004 also include a shallow gas drilling program. We will drill five to 10 wells to test the blanket sands of the Medicine Hat/Milk River formations that extend across the prospect.

## HAYS/ENCHANT

In addition to the gas potential of the area, we have steadily increased our Arcs oil production in the Scandia and greater Hays/Enchant area. We have assembled 24 sections of land at an average working interest of 85 percent. Part of the success of the program is the result of extensive use of 3-D seismic. Through proprietary shooting and trade purchases, we have acquired 37 square miles of 3-D seismic data along the Arcs oil fairway.




| Southern Alberta | |
|---|---|
| *Land holdings* | |
| Year end 2003 *(gross acres)* | 125,858 |
| Year end 2002 *(gross acres)* | 93,760 |
| % Change | 34 |
| *Net reserves (proved plus probable)* | |
| Year end 2003 *(mboe)* | 14,107 |
| Year end 2002 *(mboe)* (1) | 7,833 |
| % Change | 80 |
| *Drilling activity* | |
| 2003 gross wells | 39 |
| 2002 gross wells | 43 |
| % Change | (9) |
| *Net production* | |
| 2003 *(average daily boe)* | 2,431 |
| 2002 *(average daily boe)* | 1,152 |
| % Change | 111 |

(1) Represents proved plus 50 percent risked probable reserves.

During 2003, we drilled 12 successful Arcs oil and gas wells on 100 percent owned lands at Scandia, Hays and Enchant. One of these wells resulted in a new Arcs oil/gas discovery at Scandia which was followed up by three successful delineation wells. These four wells are now on production. We will drill up to four additional wells on this new pool discovery in 2004. Another new Arcs oil pool discovery was made at Enchant South. A delineation well is planned for second quarter of 2004. At Enchant West, three additional Arcs oil development wells were drilled as a follow-up to our 2002 discovery. We drilled three additional Arcs development oil wells at Hays, where a pressure maintenance scheme is planned for the latter half of 2004. Using proprietary 3-D seismic, we drilled an Arcs oil well adjacent to a third-party Arcs oil pool on our 100 percent working interest lands. We plan to drill up to three wells in 2004 to fully delineate this pool extension.

## MAJORVILLE/MCGREGOR

At Majorville/McGregor, we have an average working interest of 55 percent in 15 sections of land. In 2003, we participated in a seven well shallow gas program that resulted in seven comingled Medicine Hat/Milk River gas wells. Further plans to develop this natural gas resource in 2004 are under review.

## ATLEE/BUFFALO

On our 48 section 100 percent working interest land block at Atlee/Buffalo, the shallow gas drilling and recompletion activity planned for 2003 was purposefully put on hold. Capital was shifted to higher impact exploration and development opportunities at Scandia, Hays and Enchant. Our plans for 2004 include drilling 20 shallow gas wells and initiating a production optimization program at Atlee/Buffalo.

## 2004 PLANS

In 2004, we plan to spend $28.0 million in Southern Alberta. A 35 well drilling program at Scandia and Hays/Enchant will be split equally between Cretaceous gas and Arcs oil. We will also drill up to 40 shallow gas wells at Atlee/Buffalo, Scandia and Bindloss.

# Central Alberta

We recently combined the Ferrybank, Westerose and Crystal projects to form a new core area. In just over two years, we have established a land position of 21 sections in this tightly held area. We have also acquired nearly 70 square miles of 3-D seismic. Reserves have grown to 2.5 million boe and current production exceeds 1,000 boe/d.

In 2003, we drilled 13 wells in Central Alberta including two exploration wells. This activity resulted in seven (5.6 net) gas wells, three (2.6 net) oil wells and three (3.0 net) dry holes.

## FERRYBANK

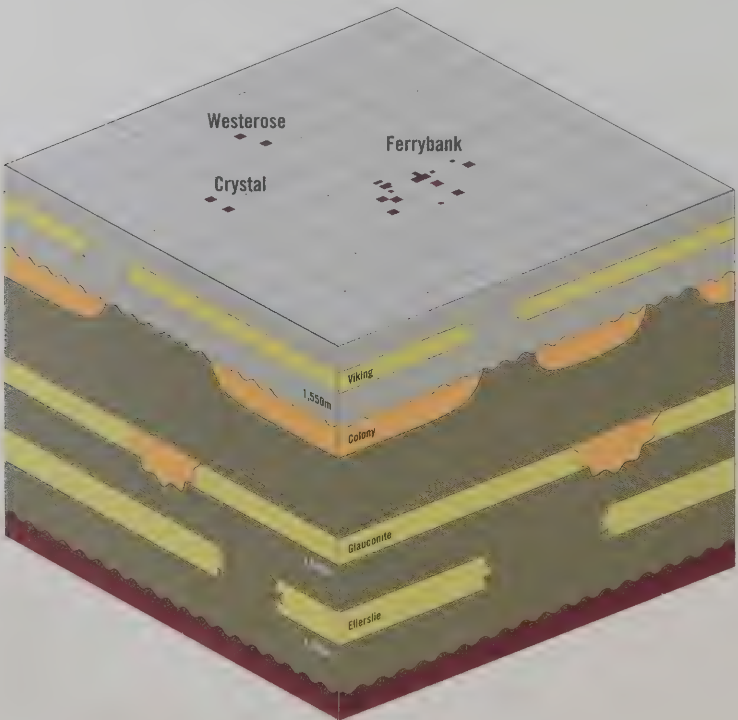
At Ferrybank, we further delineated our 2002 Ellerslie oil discovery by drilling three (2.6 net) successful wells. A fourth well drilled at 100 percent working interest resulted in the discovery of the Ellerslie gas cap. In this same well, an uphole Colony gas zone has now been completed and is on production. Three more wells were drilled that failed to find economic quantities of Ellerslie oil. Two of these wells were cased for uphole Viking potential, while the third was abandoned. Production from this pool is currently restricted to 225 bbl/d. A third-party engineering study is currently being carried out in order to achieve good production practice status from the Alberta Energy and Utilities Board, which would remove the restrictions on production. Two exploratory farm-in wells in the greater Ferrybank area were abandoned.

## WESTEROSE

At Westerose, we drilled two (1.5 net) Glauconite gas wells. Both wells are currently on production at 1.9 million cubic feet per day (1.3 net). Further drilling is planned in 2004 for the greater Westerose area and to the west at Crystal.

## 2004 PLANS

In 2004, we plan to spend $13.0 million and drill 15 wells in Central Alberta. Our program will further delineate the Ellerslie oil discovery and continue the search for new Glauconite and Colony gas reserves and production.




| Central Alberta | |
|---|---|
| *Land holdings* | |
| Year end 2003 *(gross acres)* | 13,462 |
| Year end 2002 *(gross acres)* | 8,800 |
| % Change | 53 |
| *Net reserves (proved plus probable)* | |
| Year end 2003 *(mboe)* | 2,510 |
| Year end 2002 *(mboe)* (1) | 2,174 |
| % Change | 15 |
| *Drilling activity* | |
| 2003 gross wells | 13 |
| 2002 gross wells | 2 |
| % Change | 550 |
| *Net production* | |
| 2003 *(average daily boe)* | 354 |
| 2002 *(average daily boe)* | 197 |
| % Change | 80 |

(1) Represents proved plus 50 percent risked probable reserves.

# West Central Alberta

Our primary thrust in West Central Alberta in 2003 was on exploration. We drilled 12 exploration wells, the majority of which we characterize as higher risk with higher potential rewards. Our philosophy is to expose five to 10 percent of our capital expenditures to these types of projects.

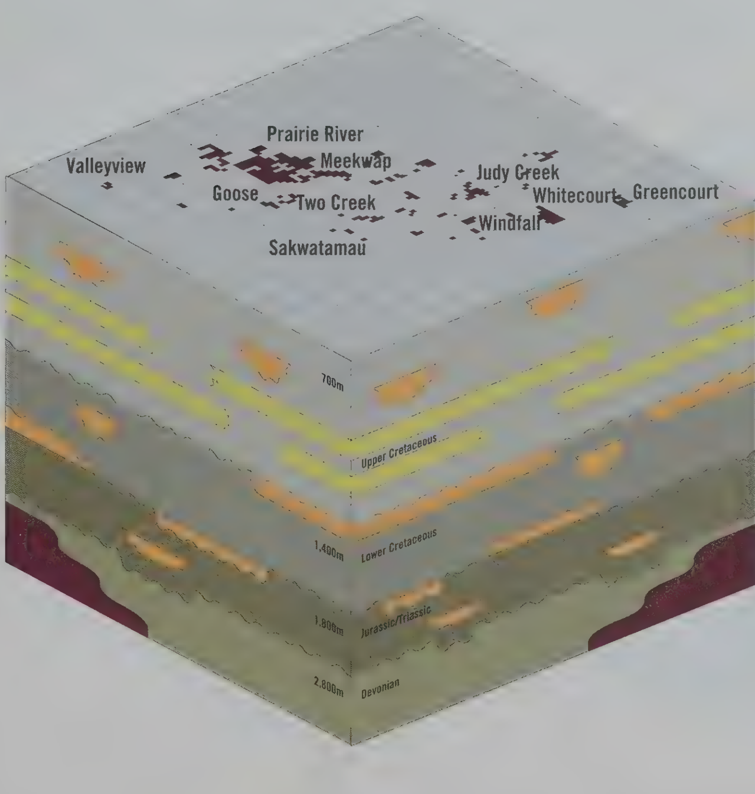
In the greater Whitecourt area, four wells were cased for gas and oil production. Two wells are now producing gas from the Notikewin and Edmonton formations at Two Creeks and Windfall, while a third well is producing Viking oil at Judy Creek. The fourth well was cased for Edmonton gas and is still under evaluation. Subsequent to year end, we drilled four new 100 percent working interest natural gas discoveries in the greater Whitecourt area. Two of these wells were placed on production before the end of the first quarter at a combined rate of 2.5 million cubic feet per day.

At Ricinus, we participated as to a 25 percent working interest in a deep Viking gas well that is now on production. Dry holes were drilled at Greencourt, Wallace, Raspberry and Goose River.

Together with our partners, we drilled another Devonian Swan Hills exploratory test (45 percent working interest) just south of the Carson Creek Swan Hills gas field. This well, which was identified from 3-D seismic, encountered a back reef facies and was abandoned. One additional exploratory test is necessary to test this prospect for a porous/permeable reef margin.

## 2004 PLANS

In 2004, we expect to spend $20.0 million and drill 22 wells in West Central Alberta, including two Devonian Swan Hills exploratory tests. However, most of our drilling will concentrate on prospects with medium risk profiles to increase gas production and deliverability. Our goal is to convert one of these projects into a core area in 2004.




### West Central Alberta

| | |
|---|---|
| *Land holdings* | |
| Year end 2003 *(gross acres)* | 186,676 |
| Year end 2002 *(gross acres)* | 174,996 |
| % Change | 7 |
| *Net reserves (proved plus probable)* | |
| Year end 2003 *(mboe)* | 1,978 |
| Year end 2002 *(mboe)* (1) | 1,129 |
| % Change | 75 |
| *Drilling activity* | |
| 2003 gross wells | 12 |
| 2002 gross wells | 10 |
| % Change | 20 |
| *Net production* | |
| 2003 *(average daily boe)* | 236 |
| 2002 *(average daily boe)* | 614 |
| % Change | (62) |

(1) Represents proved plus 50 percent risked probable reserves.

# East Central Alberta

During 2003, our focus in East Central Alberta shifted from one of growth to one of maintenance. This was due in part to increased third-party competition in the area and to our continued success in Southern Alberta. We drilled a total of 27 wells, including five exploratory wells.

## NEUTRAL HILLS

At Neutral Hills, we drilled four successful horizontal oil wells at 100 percent working interest into the previously abandoned Dina YY pool that we acquired in 2002. We also drilled one vertical Dina oil well, which resulted in a pool extension.

## CONSORT

We acquired our 100 percent working interest in the Consort property in 2002. In 2003, we shot a 100 percent proprietary 3-D seismic program and drilled 10 development wells on this new seismic. We also drilled three successful horizontal and two vertical Cummings oil wells into the W3W pool. In addition, we drilled five wells into the Dina FFF pool, resulting in two oil wells and three dry holes.

## WEST PROVOST

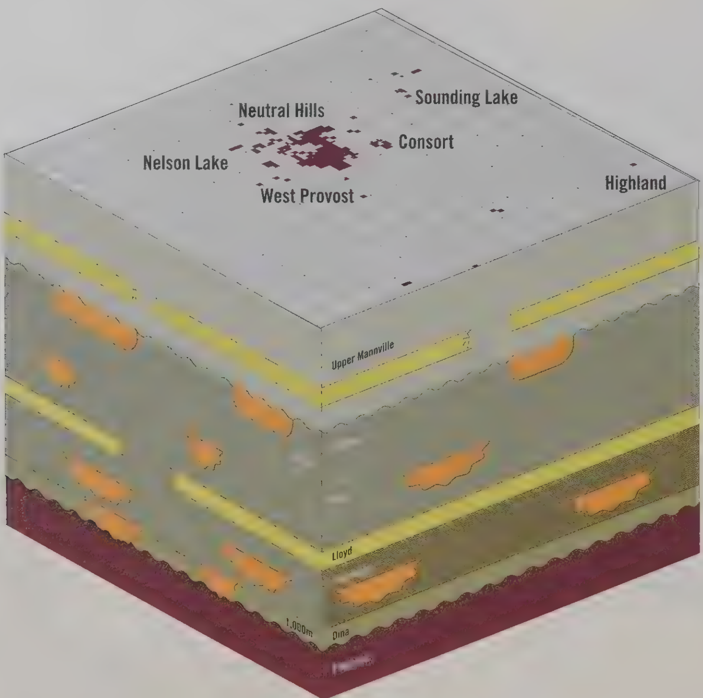
In the greater West Provost area, we drilled eight (6.0 net) wells. Seven (5.0 net) wells were cased for oil and gas potential in the Dina, Rex, Colony and Viking formations. These wells represent building-block assets characterized by more modest reserves and deliverabilities.

## NELSON LAKE

At Nelson Lake South, we drilled four 100 percent working interest wells. Two of the wells were cased for potential coal bed methane and the other two were abandoned. Subsequent to year end, we entered into discussions with a major U.S. independent producer to evaluate the coal bed methane potential in our East Central Alberta core area. As technology and data become available, we will examine the feasibility of proceeding with completion and pilot testing of our first two wells.

## 2004 PLANS

In 2004, we plan to spend $4 million in East Central Alberta. Our emphasis will be on maintaining current production levels through production optimization. In addition, we plan to drill up to 15 Viking gas/oil wells and recomplete an additional 10 wells.




| East Central Alberta | |
|---|---|
| *Land holdings* | |
| Year end 2003 *(gross acres)* | 113,541 |
| Year end 2002 *(gross acres)* | 128,308 |
| % Change | (12) |
| *Net reserves (proved plus probable)* | |
| Year end 2003 *(mboe)* | 4,701 |
| Year end 2002 *(mboe)* (1) | 5,882 |
| % Change | (20) |
| *Drilling activity* | |
| 2003 gross wells | 27 |
| 2002 gross wells | 58 |
| % Change | (53) |
| *Net production* | |
| 2003 *(average daily boe)* | 1,980 |
| 2002 *(average daily boe)* | 2,133 |
| % Change | (7) |

(1) Represents proved plus 50 percent risked probable reserves.

# Southeast Saskatchewan

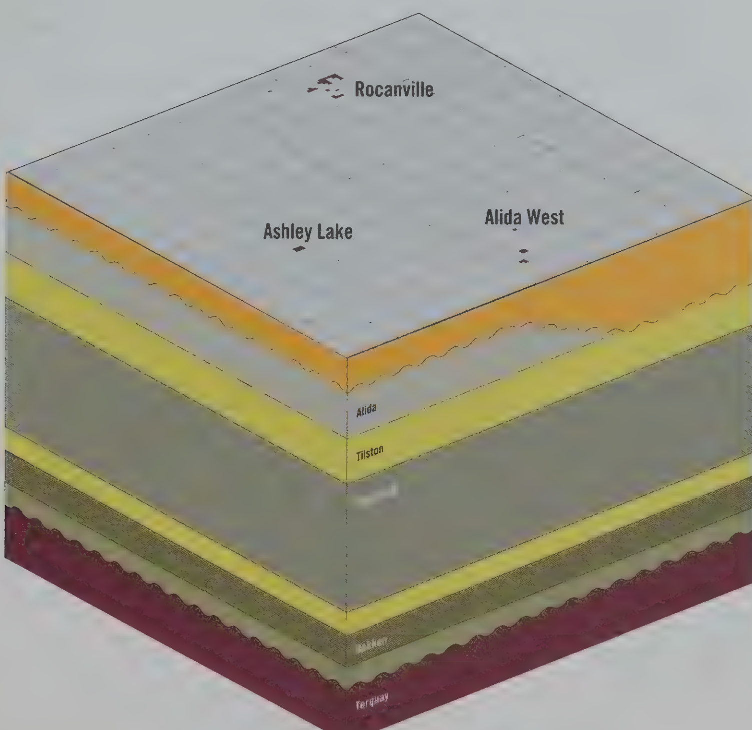
Southeast Saskatchewan was our first core area. The area, which includes Alida West, Rocanville and Ashley Lake produces light, sweet crude oil and has low operating costs, making this our highest netback region. For these reasons, the area remains attractive. However, we have scaled back development activity due to the maturity of our properties and did not carry out any drilling operations in this area during 2003.

## ROCANVILLE

At Rocanville, three stimulation attempts on the Bakken oil zone resulted in marginal production increases. In addition, we purchased a grid of 2-D trade seismic over this property to assess the potential for infill or step-out drilling.

## 2004 PLANS

During 2004, we will examine the potential for production and reserves optimization as a result of an ongoing technical engineering review and study of the area.




| Southeast Saskatchewan | |
|---|---|
| *Land holdings* | |
| Year end 2003 *(gross acres)* | 16,314 |
| Year End 2002 *(gross acres)* | 26,724 |
| % Change | (39) |
| *Net reserves (proved plus probable)* | |
| Year end 2003 *(mboe)* | 2,007 |
| Year end 2002 *(mboe)* [1] | 1,905 |
| % Change | 5 |
| *Drilling activity* | |
| 2003 gross wells | – |
| 2002 gross wells | 1 |
| % Change | (100) |
| *Net production* | |
| 2003 *(average daily boe)* | 490 |
| 2002 *(average daily boe)* | 676 |
| % Change | (28) |

(1) Represents proved plus 50 percent risked probable reserves.

# Product Marketing

Real continues to diversify and enhance the Company's crude oil and natural gas market portfolio by utilizing the services and expertise of various oil and gas marketers to sell its production. Through this marketing strategy, the objective is to obtain product prices that are higher than industry average. Crude oil and natural gas liquids are sold under short-term contracts. Gas production is sold through a combination of purchasers with over 90 percent being sold at AECO "C" spot market prices.

Real has maintained an active hedging program to manage the Company's exposure to crude oil and natural gas price fluctuations. The intent of the hedging is to set an absolute foundation on product prices to ensure that a base capital program can be funded by a threshold cash flow without exceeding the corporate objective on the ratio of debt to cash flow. By providing for a base capital program, growth can be realized through increasing production and reserve volumes without compromising the balance sheet. The hedging is implemented utilizing a combination of price swaps, collars and floors. This approach allows for a secure minimum product price with the capability to participate in any upside. The time duration of the swaps, collars and floors are varied, which allows for price averaging over a long period of time.

# Corporate Governance

Real's Board of Directors is comprised of six senior business executives with extensive knowledge and experience in the oil and gas industry. Each Director has a vested interest in the Company through common share ownership and stock options. During 2003, there were five Board meetings, five Audit Committee meetings, two Compensation Committee meetings, three Reserve Audit Committee meetings and four Environmental, Health & Safety Committee meetings. The Directors of the Company adhere to guidelines defined in the Toronto Stock Exchange Report on Corporate Governance. The Board is responsible for the stewardship of the Company, the strategic planning process, the Company's succession plan, and the Company's internal control and management information systems.

The Board is comprised of six members, four of whom are independent and unrelated, including the Chairman of the Board. Additionally, the Audit, Compensation and Reserve Audit Committees are comprised of non-management Directors. The Board as a whole does a self-assessment of its effectiveness annually. In addition, the Board as a whole evaluates the effectiveness of each committee and the contributions of individual directors. In assessing such matters, the Board conducts surveys of directors and makes recommendations for improvement. Further, the Board has placed a priority on good corporate governance practices, and the Board as a whole develops the Company's approach to corporate governance issues and regularly reviews the same.

On a minimum of an annual basis, the Board as a whole meets with management, separately from the budget process, to review and consider strategic planning. In addition, the Board reviews the strategic planning of the Company periodically in connection with regularly scheduled Board meetings and holds extraordinary strategic planning sessions based upon the need determined during the course of regularly scheduled Board meetings.

# Report of Management and Directors on Oil and Gas Reserves Disclosure[1]

Management of Real Resources Inc. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved plus probable oil and gas reserves estimated as at December 31, 2003 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2003 using constant prices and costs; and

(ii) the related estimated future net revenue.

An independent qualified reserves evaluator evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with the Annual Information Form.

The Reserve Audit Committee of the Board of Directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

**Lowell E. Jackson, P.Eng.**
President & Chief Executive Officer

**Frank P. Muller, P.Geol.**
Vice President Exploration

**D. Nolan Blades, P.Eng.**
Director

**Frans Burger**
Director

Calgary, Alberta, Canada
February 19, 2004

(1) Terms to which a meaning is ascribed in NI 51-101 have the same meaning in this form.

# Management's Discussion & Analysis

*The following discussion and analysis was prepared on March 5, 2004, and is management's assessment of Real's historical financial and operating results and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2003 and 2002, together with the notes related thereto. The reader should be aware that historical results are not necessarily indicative of future performance. This discussion contains forward-looking statements that involve risks and uncertainties. Such information, although considered reasonable by Real at the time of preparation, may prove to be incorrect and actual results may differ materially from those anticipated in the statements made. Where converted to a barrel of oil equivalent basis, all natural gas production results have been converted at the rate of 6 thousand cubic feet to 1 barrel of oil equivalent.*

## FINANCIAL HIGHLIGHTS OF 2003

The Company achieved record activity levels in 2003 with a successful drilling program that resulted in the fifth consecutive year of growth in production revenue and total production volumes. Real successfully completed the planned shift to natural gas activities in its capital program with the accomplishment of record gas production levels in the fourth quarter of 2003 of 18.8 million cubic feet per day. This change in emphasis successfully positioned the Company to take advantage of the recovery in natural gas prices that took place during 2003.

## DETAILED FINANCIAL ANALYSIS

### PRODUCTION REVENUE

| Production revenue summary *($ thousands)* | Years ended December 31 2003 | 2002 | % change |
|---|---|---|---|
| Oil and natural gas liquids revenue | 45,100 | 41,557 | 9 |
| Natural gas revenue | 28,816 | 12,887 | 124 |
| | 73,916 | 54,444 | 36 |
| Hedging losses | (2,368) | (1,993) | 19 |
| Royalty income | 624 | 103 | 506 |
| Total production revenue | 72,172 | 52,554 | 37 |

Revenues from crude oil, liquids and natural gas sales increased by $19.6 million or 37 percent to $72.2 million in 2003 from $52.6 million in 2002. Over 80 percent of the increase was the direct result of increased natural gas revenues with the recovery in gas prices and increased production levels from the Scandia area being the main contributing factors. The Company's realized gas price increased 60 percent to $5.96 per mcf from $3.73 per mcf. Average natural gas production for the year increased by 40 percent to 12.8 million cubic feet per day from 9.1 million cubic feet per day in the previous year, almost entirely from the Scandia area. Crude oil and liquids production increased marginally to 3,352 barrels per day from 3,248 barrels per day in the previous year. Production additions at Hays/Enchant and Scandia arising from the 2003 drilling program as well as the full-year impact of the property acquisition made in the Consort area late in 2002 more than offset declines at Neutral Hills and Sounding Lake.

The following table summarizes the commodity prices realized during 2003 and 2002.

| Average realized price | Years ended December 31 2003 | 2002 | % change |
|---|---|---|---|
| Oil and liquids *($/bbl, excluding hedging)* | 36.86 | 35.05 | 5 |
| Oil and liquids *($/bbl, including hedging)* | 35.65 | 33.73 | 6 |
| Natural gas *($/mcf, excluding hedging)* | 6.15 | 3.86 | 59 |
| Natural gas *($/mcf, including hedging)* | 5.96 | 3.73 | 60 |
| Total average realized price *($/boe, including hedging)* | 35.70 | 30.12 | 19 |

| Total oil and gas revenue (*$/boe*) | Years ended December 31 2003 | 2002 | % change |
|---|---|---|---|
| Production revenue | 36.88 | 31.26 | 18 |
| Hedging losses | (1.18) | (1.14) | 4 |
| | 35.70 | 30.12 | 19 |
| Royalty income | 0.31 | 0.05 | 520 |
| Total average realized price | 36.01 | 30.17 | 19 |

West Texas Intermediate ("WTI") is the benchmark for North American oil prices and is the crude type against which the NYMEX futures contract is priced. Canadian crude oil prices are based upon refiners' postings at Alberta hubs like Edmonton and Hardisty. These postings represent the WTI price at Cushing, Oklahoma less a transportation differential, the Canadian/U.S. foreign exchange rate, and, to some extent, an adjustment for regional market conditions.

Real's average field prices reflect the refiners' posted price at the market centers less deductions for transportation from the field and adjustments for Real's product quality relative to the posted product including the quality differential on natural gas liquids.

| Crude oil and natural gas liquids prices | Years ended December 31 2003 | 2002 | % change |
|---|---|---|---|
| WTI (*U.S.$/bbl*) | 31.06 | 26.08 | 19 |
| Average exchange rate (*Cdn.$/U.S.$*) | 1.40 | 1.57 | (11) |
| WTI (*Cdn.$/bbl*) | 43.53 | 40.95 | 6 |
| Less: Differential WTI to Edmonton | (0.43) | (1.34) | (68) |
| Edmonton light sweet posting (*Cdn.$/bbl*) | 43.10 | 39.61 | 9 |
| Less: Quality differential & transportation to Edmonton (including liquids differential) | (6.24) | (4.56) | 37 |
| Real's average field price (*Cdn.$/bbl*) | 36.86 | 35.05 | 5 |

U.S. natural gas prices are typically referenced off NYMEX at Henry Hub, Louisiana while Alberta natural gas is referenced to AECO "C".

| Natural gas prices | Years ended December 31 2003 | 2002 | % change |
|---|---|---|---|
| AECO "C" (*Cdn.$/mcf*) | 6.68 | 4.08 | 64 |
| Less: TCPL Alberta system charges | (0.19) | (0.17) | 12 |
| Variance: Real pool price vs. spot | (0.34) | (0.05) | 580 |
| Real's average gas price (*Cdn.$/mcf*) | 6.15 | 3.86 | 59 |

The following table summarizes the impact on oil and gas revenue of the Company's production activities, prices and hedging activities.

| Variance analysis | (*$ millions*) | % change |
|---|---|---|
| Reported 2002 oil and gas revenue | 52.6 | |
| Increase due to realized gas price | 10.7 | 55 |
| Increase due to gas production volumes | 5.2 | 26 |
| Increase due to realized oil and liquids price | 2.2 | 11 |
| Increase due to oil and liquids production volumes | 1.3 | 7 |
| Increase due to royalty income | 0.5 | 3 |
| Decrease due to hedging activities | (0.3) | (2) |
| Total increase, net | 19.6 | 100 |
| Reported 2003 oil and gas revenue | 72.2 | |

## ROYALTY EXPENSE

Royalties have increased to $15.1 million for 2003 from $10.1 million in 2002. The increase in royalty expense for 2003 is primarily a result of increased oil and gas revenues. Royalties as a percentage of gross revenue increased to 20.4 percent in 2003 from 18.5 percent in 2002. Royalty rates for 2003 are higher due to the Company's successful activities in the Scandia and Hays/Enchant areas, which are primarily on crown land. The corresponding change in the composition of crown versus non-crown production has resulted in a higher overall average royalty burden. Freehold and GORR royalties in 2003 were lower as a percentage of revenue due to several wells that were royalty free in the third quarter pending capital expenditure recoveries which were fully recovered by the end of the year.

| | Years ended December 31 | | |
|---|---|---|---|
| **Royalty expense** *($ thousands, except where noted)* | 2003 | 2002 | % change |
| Crown | 11,119 | 7,103 | 57 |
| Freehold and GORR | 4,373 | 3,573 | 22 |
| Total royalties | 15,492 | 10,676 | 45 |
| ARTC | (414) | (581) | (29) |
| Total royalties, net of ARTC | 15,078 | 10,095 | 49 |
| Total royalties *($/boe)* | 7.73 | 6.13 | 26 |
| Total royalties, net of ARTC *($/boe)* | 7.52 | 5.80 | 30 |

| | Years ended December 31 | | |
|---|---|---|---|
| **Average royalty rates** *(% of sales, excluding hedging activities)* | 2003 | 2002 | % change |
| Crown | 15.0 | 13.0 | 15 |
| Freehold and GORR | 5.9 | 6.6 | (11) |
| Total royalties | 20.9 | 19.6 | 7 |
| ARTC | (0.5) | (1.1) | (55) |
| Total royalties, net of ARTC | 20.4 | 18.5 | 10 |

## OTHER INCOME

The Company has settled a legal dispute with a third-party gas processor relating to the processing of contracted gas volumes from Real's Scandia gas project in the first half of 2003. The settlement included a $0.6 million cash payment to Real plus a revised gas processing agreement.

## OPERATING EXPENSES

Operating expenses in 2003 increased by 44 percent to $15.1 million from $10.5 million in 2002, primarily as a result of increased production volumes. Operating expenses on a unit of production basis increased to $7.52 per barrel of oil equivalent in 2003 from $6.03 per barrel of oil equivalent during 2002. Operating expenses per boe increased due mainly to higher work-over and repair costs as well as higher rates on electricity and fuel.

| | Years ended December 31 | | |
|---|---|---|---|
| **Operating expenses** *($ thousands, except where noted)* | 2003 | 2002 | % change |
| Operating expenses | 15,075 | 10,498 | 44 |
| Operating expenses *($/boe)* | 7.52 | 6.03 | 25 |

## OPERATING NETBACK

Operating netbacks increased 15 percent to $21.94 per boe for 2003 compared to $19.15 per boe for 2002.

| | Years ended December 31 | | |
|---|---|---|---|
| Operating netback *($/boe)* | 2003 | 2002 | % change |
| Production revenue | 36.88 | 31.26 | 18 |
| Royalty income | 0.31 | 0.05 | 520 |
| | 37.19 | 31.31 | 19 |
| Total royalties *(excluding ARTC)* | (7.73) | (6.13) | 26 |
| Operating expenses | (7.52) | (6.03) | 25 |
| Operating netback | 21.94 | 19.15 | 15 |

| | Years ended December 31 | | |
|---|---|---|---|
| Operating netback – oil properties *($/bbl)* | 2003 | 2002 | % change |
| Production revenue | 36.89 | 34.54 | 7 |
| Royalty income | 0.29 | 0.03 | 867 |
| | 37.18 | 34.57 | 8 |
| Total royalties *(excluding ARTC)* | (7.59) | (6.65) | 14 |
| Operating expenses | (8.27) | (5.86) | 41 |
| Operating netback | 21.32 | 22.06 | (3) |

| | Years ended December 31 | | |
|---|---|---|---|
| Operating netback – gas properties *($/boe, includes natural gas liquids production)* | 2003 | 2002 | % change |
| Production revenue | 36.87 | 24.52 | 50 |
| Royalty income | 0.34 | 0.12 | 183 |
| | 37.21 | 24.64 | 51 |
| Total royalties *(excluding ARTC)* | (7.92) | (5.05) | 57 |
| Operating expenses | (6.50) | (6.37) | 2 |
| Operating netback | 22.79 | 13.22 | 72 |

## GENERAL AND ADMINISTRATIVE EXPENSES

Gross general and administrative expenses increased 14 percent to $6.0 million in 2003 compared to $5.3 million in 2002. This resulted mainly from the increase in full-time staff required as a result of the increased size of the Company's operations and its larger asset base. On a unit of production basis, gross general and administrative expenses decreased marginally to $3.02 per barrel of oil equivalent in 2003 from $3.05 per barrel of oil equivalent in 2002.

Net general and administrative expenses increased 12 percent to $3.2 million in 2003 compared to $2.9 million in 2002. The magnitude of overhead recoveries is a function of activity levels and the degree to which the Company operates its joint venture interests. Real operates approximately 90 percent of its production and generally operates all of the drilling activity. Overhead recoveries for 2003 were $1.6 million compared to $1.4 million in 2002. The increase is primarily a function of the higher drilling activities undertaken in 2003. Real capitalizes general and administrative expenses associated with salaries and benefits attributed to the Company's exploration and development staff as these expenses are associated with adding reserves versus the cost of producing reserves. During 2003, these costs increased as a result of an increase in the number of employees involved in these activities. On a net unit of production basis, general and administrative expenses decreased 3 percent to $1.59 per barrel of oil equivalent in 2003 from $1.64 per barrel of oil equivalent in 2002.

| General and administrative expenses *($ thousands)* | 2003 | 2002 | % change |
|---|---|---|---|
| | Years ended December 31 | | |
| Gross expense | 6,049 | 5,317 | 14 |
| Overhead recoveries | (1,625) | (1,439) | 13 |
| Subtotal | 4,424 | 3,878 | 14 |
| Capitalized expense | (1,228) | (1,023) | 20 |
| Net expense | 3,196 | 2,855 | 12 |

| Average cost per barrel equivalent *($/boe)* | 2003 | 2002 | % change |
|---|---|---|---|
| | Years ended December 31 | | |
| Gross expense | 3.02 | 3.05 | (1) |
| Overhead recoveries | (0.81) | (0.83) | (2) |
| Subtotal | 2.21 | 2.22 | – |
| Capitalized expense | (0.62) | (0.58) | 7 |
| Net expense | 1.59 | 1.64 | (3) |

## INTEREST EXPENSE

Bank debt increased to $62.3 million during 2003 compared to $53.7 million in 2002 as a result of the increase in exploration and development activities in the year. Interest expense for 2003 increased 53 percent to $2.4 million from $1.6 million in 2002. Interest expense was $1.20 per barrel of oil equivalent, an increase of 33 percent from $0.90 per barrel of oil equivalent in 2002. Interest expense increased due to the higher average debt levels carried by the Company. The all-inclusive cost of borrowing was 4.5 percent in 2003, a slight increase from the average cost of borrowing of 4.3 percent in 2002.

| Interest expense *(including bank fees)($ thousands, except where noted)* | 2003 | 2002 | % change |
|---|---|---|---|
| | Years ended December 31 | | |
| Interest expense | 2,401 | 1,565 | 53 |
| Interest expense per boe *($/boe)* | 1.20 | 0.90 | 33 |
| Average debt outstanding | 53,000 | 36,100 | 47 |
| Average effective interest rate *(%)* | 4.5 | 4.3 | 5 |

## DEPLETION, DEPRECIATION AND SITE RESTORATION

Depletion, depreciation and site restoration expense increased to $20.2 million in 2003 from $17.4 million in 2002, a 16 percent increase. This increase was primarily due to increased production levels. Depletion, depreciation and site restoration increased to $10.10 per boe during 2003 compared to $9.99 per boe in 2002.

| Depletion, depreciation and site restoration *($ thousands, except where noted)* | 2003 | 2002 | % change |
|---|---|---|---|
| | Years ended December 31 | | |
| Depletion and depreciation | 19,298 | 16,501 | 17 |
| Provision for site restoration | 950 | 907 | 5 |
| | 20,248 | 17,408 | 16 |
| Depletion, depreciation and site restoration *($/boe)* | 10.10 | 9.99 | 1 |

## CEILING TEST

In accordance with the Canadian Institute of Chartered Accountants' full cost accounting guidelines, Real performs an annual ceiling test calculation using year-end prices. The Company also performs quarterly ceiling test calculations using prices received for product sales on the last day of each quarter. No write-down was required for the year ended December 31, 2003, based on year-end commodity prices of $40.92 per bbl for crude oil and $6.08 per mcf for natural gas. No write-down was required for the year ended December 31, 2002, based on year-end commodity prices of $48.97 per bbl for crude oil and $5.70 per mcf for natural gas.

## INCOME TAXES

In June 2003, the Federal Government introduced legislation to reduce the general corporate income tax rate on income from resource activities from 28 percent to 21 percent over a five-year period starting January 1, 2003, bringing the resource industry in line with the general corporate income tax rate. As part of the corporate income tax reduction, the legislation also plans for the elimination of the existing 25 percent resource allowance and the introduction of a deduction for actual provincial crown royalties paid. In addition, the Alberta corporate income tax rate changed from 13.0 percent to 12.5 percent. As a result of these changes, which are considered to be substantively enacted for Canadian GAAP purposes, the Company's future tax liability decreased by $7.0 million.

The Company's future income tax expense was $0.7 million, an 81 percent decrease from $3.6 million in 2002. This was primarily due to the recovery of $7.0 million related to the scheduled rate reduction on future estimated revenue.

The effective tax rate for 2003 was 8.3 percent, an 80 percent decrease from the average rate of 41.7 percent in 2002.

The Company's capital tax expense increased 17 percent to $0.7 million in 2003 from $0.6 million in 2002. The Large Corporation Tax was higher due to the additional debt undertaken in 2003 that was used to finance the Company's capital expenditure program. Real paid no current income tax in 2003.

| | Years ended December 31 | | |
|---|---|---|---|
| Income taxes *($ thousands, except where noted)* | 2003 | 2002 | % change |
| Future income taxes | 671 | 3,613 | (81) |
| Capital taxes | 720 | 613 | 17 |
| Total income taxes | 1,391 | 4,226 | (67) |
| Total income taxes *($/boe)* | 0.69 | 2.43 | (72) |
| Effective tax rate *(%)* | 8.3 | 41.7 | (80) |

At the end of 2003, Real had approximately $96.2 million of accumulated tax pools that are available for deduction against future earnings compared to $74.8 million at December 31, 2002.

| Summary of tax pools at December 31, 2003 *($ thousands)* | Maximum available balance | Maximum annual deduction |
|---|---|---|
| Canadian Exploration Expense | 5,107 | 100% |
| Canadian Development Expense | 29,030 | 30% |
| Canadian Oil & Gas Property Expense | 32,582 | 10% |
| Undepreciated Capital Cost | 28,092 | 4-30% |
| Foreign Exploration & Development Expense | 430 | 10% |
| Other | 964 | 8-20% |
| Total | 96,205 | |

## NET EARNINGS, NETBACKS AND CASH FLOW FROM OPERATIONS

### Net earnings

Net earnings increased 160 percent to $15.4 million in 2003 from $5.9 million in 2002. Net earnings per share increased 123 percent to $0.67 per share in 2003 from $0.30 per share in 2002. Similarly, diluted net earnings per share increased 128 percent to $0.66 per share in 2003 from $0.29 per share in 2002.

| **Netbacks** *($/boe)* | Years ended December 31 2003 | 2002 | % change |
|---|---|---|---|
| Production revenue | 36.01 | 30.17 | 19 |
| Net royalties | (7.52) | (5.80) | 30 |
| Operating expenses | (7.52) | (6.03) | 25 |
| Operating netback | 20.97 | 18.34 | 14 |
| Other income | 0.30 | – | n/a |
| General and administrative expenses | (1.59) | (1.64) | (3) |
| Interest expense | (1.20) | (0.90) | 33 |
| Current taxes | (0.36) | (0.36) | – |
| Cash flow netback | 18.12 | 15.44 | 17 |
| Depletion, depreciation and site restoration | (10.10) | (9.99) | 1 |
| Future income taxes | (0.33) | (2.07) | (84) |
| Corporate netback | 7.69 | 3.38 | 127 |

### Cash flow from operations

Cash flow from operations increased 35 percent to $36.1 million in 2003 from $26.8 million in 2002. Cash flow from operations per share increased 16 percent to $1.58 per share in 2003 from $1.36 per share in 2002. Diluted cash flow from operations increased 16 percent to $1.56 per share from $1.34 per share.

*Corporate netbacks and cash flow from operations per share are non-GAAP terms that represent net earnings adjusted for non-cash items on a boe and per share basis. The Company evaluates its performance based on these measures. The Company considers corporate netbacks a key measure as it demonstrates its profitability relative to current commodity prices. The Company considers cash flow a key measure as it demonstrates the Company's ability to generate cash flow necessary to fund future growth through capital investment and to repay debt.*

| *($ thousands)* | Years ended December 31 2003 | 2002 | % change |
|---|---|---|---|
| Net earnings | 15,383 | 5,907 | 160 |
| Non-cash items: | | | |
| Depletion, depreciation and site restoration | 20,248 | 17,408 | 16 |
| Future income tax expense | 671 | 3,613 | (81) |
| Site restoration and abandonment expenditures | (160) | (99) | 62 |
| Cash flow from operations | 36,142 | 26,829 | 35 |

| *(thousands)* | Years ended December 31 2003 | 2002 | % change |
|---|---|---|---|
| Weighted average outstanding shares | | | |
| Basic | 22,804 | 19,716 | 16 |
| Diluted (treasury stock method) | 23,226 | 20,084 | 16 |
| Outstanding shares December 31 | | | |
| Basic | 23,351 | 20,507 | 14 |
| Diluted (treasury stock method) | 23,774 | 20,876 | 14 |

| Per share information | 2003 | Years ended December 31<br>2002 | % change |
|---|---|---|---|
| Net earnings | 15,383 | 5,907 | 160 |
| Net earnings per share | | | |
| Basic *($/share)* | 0.67 | 0.30 | 123 |
| Diluted *($/share)* | 0.66 | 0.29 | 128 |
| Cash flow from operations | 36,142 | 26,829 | 35 |
| Cash flow from operations per share | | | |
| Basic *($/share)* | 1.58 | 1.36 | 16 |
| Diluted *($/share)* | 1.56 | 1.34 | 16 |
| Total assets | 205,105 | 163,346 | 26 |
| Total assets per share | | | |
| Basic *($/share)* | 8.99 | 8.28 | 9 |
| Diluted *($/share)* | 8.83 | 8.13 | 9 |
| Book value (shareholders' equity) | 89,618 | 61,624 | 45 |
| Book value per share | | | |
| Basic *($/share)* | 3.93 | 3.13 | 26 |
| Diluted *($/share)* | 3.86 | 3.07 | 26 |

## CAPITAL EXPENDITURES

Real executes its growth strategy through exploration, exploitation and development activities supplemented with strategic property and corporate acquisitions. Net capital expenditures in 2003 were $59.5 million compared to $54.3 million in 2002 (before the tax gross-up on acquisitions). The corporate acquisition of Belmont Energy Ltd. was included in 2002 capital expenditures. These expenditures are summarized as follows:

| Capital expenditures *($ thousands)* | 2003 | Years ended December 31<br>2002 | % change |
|---|---|---|---|
| Exploration and development expenditures | | | |
| Lease acquisition | 9,143 | 4,408 | 107 |
| Geological and geophysical | 5,159 | 3,270 | 58 |
| Drilling and completion | 31,885 | 25,386 | 26 |
| Facilities and equipment | 13,199 | 8,057 | 64 |
| Total exploration and development expenditures | 59,386 | 41,121 | 44 |
| Other expenditures | 217 | 62 | 250 |
| Total capital expenditures | 59,603 | 41,183 | 45 |
| Proceeds from property dispositions | (104) | (4,366) | (98) |
| Property acquisitions | – | 11,588 | (100) |
| Corporate acquisitions | – | 5,865 | (100) |
| Net capital expenditures before tax gross-up on acquisitions | 59,499 | 54,270 | 10 |
| Future income tax gross-up on corporate acquisitions | 65 | 2,646 | (98) |
| Net capital expenditures | 59,564 | 56,916 | 5 |

Funding for capital expenditures and acquisitions was provided by cash flow from operations, the proceeds from the issuance of equity, bank debt, and working capital.

## CAPITALIZATION AND FINANCIAL RESOURCES

At December 31, 2003, the Company had an $85.0 million financing commitment with a Canadian chartered bank, which provided for an extendible revolving term credit facility. At the end of the year, $62.3 million of the facility was drawn.

In addition to this debt, Real had a working capital deficiency of $5.4 million for a total net debt of $67.7 million. The ratio of total net debt as at December 31, 2003, to 2003 cash flow was 1.9 times. The ratio of total net debt as at December 31, 2003, to the annualized fourth quarter 2003 cash flow was 1.7 times.

## OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of common shares without par value, and an unlimited number of first, second, third and fourth class preferred shares issuable in series. As at December 31, 2003, there were 23.4 million outstanding common shares compared to 20.5 million outstanding shares at December 31, 2002. There were no preferred shares outstanding during these periods. Employees and directors have been granted options to purchase common shares under the Company Stock Option Plan. This plan and its terms and outstanding balance are disclosed in note 6 to the Consolidated Financial Statements.

The Company obtained regulatory approval under Canadian securities laws to purchase common shares under two consecutive Normal Course Issuer Bids which commenced in June 2002 and may continue until June 2004. Under the terms of the bids, the Company repurchased for cancellation 0.7 million shares in 2003 and as of December 31, 2003, was entitled to purchase for cancellation an additional 0.9 million common shares.

## CONTRACTUAL OBLIGATIONS

The Company has entered into various commitments primarily related to the Calgary office lease. The following table summarizes the outstanding contractual obligations of the Company for the next five years and thereafter:

| *($ thousands)* | 2004 | 2005 | 2006 | 2007 | 2008 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Office lease | 268 | 268 | 268 | 268 | 268 | 45 | 1,385 |
| Pipeline transportation | 175 | 175 | 117 | – | – | – | 467 |
| Other | 120 | 56 | – | – | – | – | 176 |
| | 563 | 499 | 385 | 268 | 268 | 45 | 2,028 |

## OFF-BALANCE SHEET ARRANGEMENTS AND RELATED PARTY TRANSACTIONS

The Company has not entered into any off-balance sheet transactions or into any related party transactions.

## CRITICAL ACCOUNTING ESTIMATES

Management is required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. The following discussion outlines the accounting policies and practices that are critical to determining Real's financial results.

### (a) Full cost accounting

Real follows the Canadian Institute of Chartered Accountants' guideline on full cost accounting in the oil and gas industry to account for oil and gas properties. Under this method, all costs associated with the acquisition of, exploration for and development of natural gas and crude oil reserves are capitalized and costs associated with production are expensed. The capitalized costs are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves. Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of depreciation, depletion and amortization ("DD&A"). A downward revision in a reserve estimate could result in a higher DD&A charge to earnings.

In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates, the excess must be written off as an expense charged against earnings. In the event of a property disposition, proceeds are normally deducted from the full cost pool without recognition of a gain or loss unless there is a change in the DD&A rate of 20 percent or greater.

**(b) Oil and gas reserves**

Real's proved oil and gas reserves are 100 percent evaluated and reported on by an independent petroleum engineering consultant. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to a number of uncertainties and various interpretations. These estimates are the basis for the determination of the fair market value and the estimated net revenue stream of these reserves. The Company expects that its estimate of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and economics of recovery based on cash flow forecasts.

**(c) Asset impairment**

The above noted forecasts are used in the determination of future net revenue (using prices in effect at the end of the year and held constant) when performing the ceiling test, which is the test undertaken to determine if the unamortized capital costs or carrying amount associated with these reserves are in excess of the future net revenue as calculated above. If the sum of the net revenue streams is less than the carrying amount, the impairment loss is charged to earnings.

**(d) Future income tax**

The Company follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax base, using substantively enacted future income tax rates. In June 2003, the Federal Government introduced a gradual reduction in the general corporate income tax rate over a five year period starting January 1, 2003 (see Income Taxes in the MD&A). The impact of the new legislation requires the Company to schedule out all existing temporary differences, identify the accounting and tax values during the five year phase-in period for the declining tax rates and recalculate the future income tax balance using tax rates in effect when temporary differences reverse. The above noted forecasts of estimated net revenue streams are utilized to calculate the future tax provision and, as such, are subject to revisions, both upwards and downwards, that are not known at this time. In addition to these revisions, future capital activities can impact the timing of the reversal of any temporary differences. These differences can have an impact on the amount of future taxes determined at a point in time, and to the extent that these differences are created, they can impact the charge against earnings for future income taxes.

**(e) Future site reclamation and abandonment costs**

The Company recognizes a provision for future site reclamation and abandonment costs calculated on the unit-of-production basis over the life of the petroleum and natural gas properties based on total estimated reserves (see above) and an estimated future abandonment liability.

The estimate of the future abandonment liability is determined by management based on the best available information using current costs and current technology. These estimates are subject to change over time and, as such, may impact the charge against income for future site reclamation and abandonment costs.

## IMPACT OF NEW ACCOUNTING PRONOUNCEMENTS

In November 2002, the Accounting Standards Board amended its accounting guidelines on hedging relationships. The guideline specifies certain criteria that must be met for an item to be accounted for as a hedge. The criteria includes ensuring the hedge meets the risk management objective and strategy, the instrument must be designated as a hedge and the hedge must be effective. The guideline is effective for years beginning on or after July 1, 2003. Real's current hedging program does not qualify as a hedge under the amended guidelines and, as a result, a mark to market calculation will be done in 2004. There will potentially be more volatility in earnings as a result of the adoption of this guideline.

In December 2002, the Accounting Standards Board approved a standard on accounting for asset retirement obligation effective for fiscal years beginning on January 1, 2004. The standard requires the recognition of a liability for obligations associated with the retirement of property, plant and equipment when the liability is incurred. The liability would be recognized initially at fair value (obligation is discounted using the credit-adjusted risk-free interest rate) and the resulting amount would be capitalized as part of the asset. In subsequent periods, the Company would recognize "interest" on the liability and adjust the carrying amount of the asset and the liability for changes in estimates of the amount or timing of cash flow. Under existing standards, the liability for future removal and site restoration costs are recognized using a cost-accumulation measurement over the useful life of the asset accrued over the life of the asset and the obligation is not discounted. Real is currently assessing these requirements to ensure it complies with the new standards starting in 2004.

In December 2002, the Accounting Standards Board issued an exposure draft on proposed amendments to Handbook Section, Stock-Based Compensation effective for fiscal years beginning on or after January 1, 2004. The proposals would require all stock options to be expensed at fair value. Under existing standards, companies have the option of disclosing this information in the notes to the financial statements rather than expensing stock options. The Company will be adopting the requirements in 2004 retroactively without restatement. The charge to Retained Earnings on January 1, 2004 will be $0.7 million.

In September 2003, the Accounting Standards Board issued an amendment to its accounting guideline "Full Cost Accounting in the Oil and Gas Industry" effective for fiscal years beginning on or after January 1, 2004. Under the new guideline, the ceiling test would involve a two-step process. The first step would determine whether a write-down is required by comparing the carrying value of the properties to the undiscounted cash flow of the proved reserves (based on management's best estimate of future prices) plus the lower of cost and market value of unproved properties. If a Company fails the first step, the carrying value of the properties will be written down to the discounted value of the proved plus probable reserves (based on management's best estimate of future prices) plus lower of cost and market of unproved properties. Under existing standards, the undiscounted cash flow amount is based on the commodity prices existing at the balance sheet date. Real is currently assessing these requirements to ensure it complies with the new guidelines starting in 2004.

## RISKS AND UNCERTAINTIES

There are a number of risks facing participants in the Canadian oil and gas industry. Some of the risks are common to all businesses while others are specific to the sector. The following reviews the general and specific risks and includes Real's approach to managing these risks.

The Company is engaged in the exploration, development, production and acquisition of crude oil and natural gas. Real's business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates, and currency exchange rates. Operational risks include competition, environmental factors, reservoir performance uncertainties, a complex regulatory environment and safety concerns.

The Company minimizes its business risks by operating a large number of its properties. This enables Real to control the timing, direction and costs related to exploration and development opportunities. The geological focus is on areas in which the prospects are well understood by management. Technological tools are regularly used to reduce risk and increase the probability of success. The Company closely follows all government regulations and has an up to date emergency response plan that has been communicated to all field operations by management. Real also carries insurance coverage to protect itself against potential losses. Maintaining a highly motivated and talented staff of petroleum and natural gas professionals further minimizes the business risk.

Real relies on various sources of funding to support its growing capital expenditure program:

- Internally generated cash flow provides the minimum level of funding on which the Company's annual capital expenditure program is based;
- Debt may be utilized to expand capital programs when it is deemed appropriate; and
- New equity, if available and if on favorable terms, may be utilized to expand exploration programs.

The Company is exposed to commodity price and market risk for its principal products of petroleum and natural gas. Commodity prices are influenced by a wide variety of factors of which most are beyond the control of Real. To manage this risk, the Company has entered into a number of short-term financial derivatives for hedging purposes. These derivatives include contracts related to oil and gas prices as well as foreign exchange rates. Real has also minimized its exposure to increased interest rates by entering into short-term contracts for interest rate swap.

Inflation risks subject the Company to potential erosion of product netbacks. For example, increasing domestic prices for oil and natural gas production equipment and services can inflate the costs of operations.

The supply of service and production equipment at competitive prices is critical to the ability to add reserves at a competitive cost and produce these reserves in an economic and timely fashion. In periods of increased activity, these services and supplies can become difficult to obtain. The Company attempts to mitigate this risk by developing strong long-term relationships with suppliers and contractors and maintaining an appropriate inventory of production equipment.

Demand for crude oil and natural gas produced by the Company exists within Canada and the United States; however, crude oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals. Demand for natural gas liquids is dictated predominately by demand for petrochemicals in North American and off-shore markets. Real mitigates the risks as follows:

- Crude oil production is high quality and hence not subject to adverse quality differentials;
- Natural gas is connected to mature pipeline infrastructure that operates with minimal interruptions;
- Exploration efforts target high-quality oil and liquid-rich natural gas reserves;
- Exploration efforts are concentrated in core regions where marketing expertise levels are highest. Marketing synergies can be achieved with the existing production base;
- Sale arrangements vary in term and pricing structure to develop a portfolio to minimize risk of exposure to any one market; and
- Financial instruments are used where appropriate to manage commodity price volatility.

In 1994, the United Nations' Framework on Climate Change came into force and three years later led to the Kyoto Protocol, which requires nations to reduce their emissions of carbon dioxide and, therefore, greenhouse gases. The Government of Canada has ratified the Kyoto Protocol. Reductions in greenhouse gases from producers in geographic areas where Real has operations may be required, which could result in, among other things, increased operating and capital expenditures for those producers. This may make certain production of crude oil or natural gas by those producers uneconomic, resulting in reductions in such production. The Company is unable to predict the effect on the future earnings of Real of the ratification of the Kyoto Protocol by the Government of Canada.

The Company is committed to maximizing shareholder value in an environmentally and socially responsible and safe manner. To this end, Real is actively involved in the Canadian Association of Petroleum Producers ("CAPP") Stewardship initiative. This voluntary initiative encourages members to continually improve their environment, health and safety performance and to report their progress to all stakeholders. The Company is pleased to report that CAPP has recognized Real's participation at a Gold level, which acknowledges an open and transparent account of our environment, health and safety performance on a yearly basis and a leadership role in the improvement of these issues.

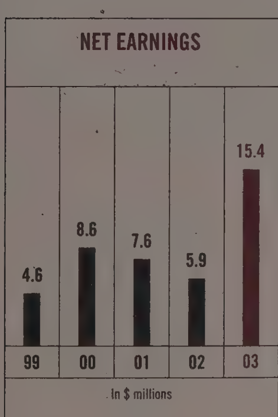
## SELECTED ANNUAL INFORMATION

| | Years ended December 31 | | |
|---|---|---|---|
| *($ thousands, except per share amounts)* | 2003 | 2002 | 2001 |
| Production revenue | 72,172 | 52,554 | 51,527 |
| Net earnings | 15,383 | 5,907 | 7,607 |
| Per share – basic | 0.67 | 0.30 | 0.41 |
| Per share – diluted | 0.66 | 0.29 | 0.40 |
| Total assets | 205,105 | 163,346 | 121,038 |
| Total net debt | 67,697 | 56,570 | 32,689 |

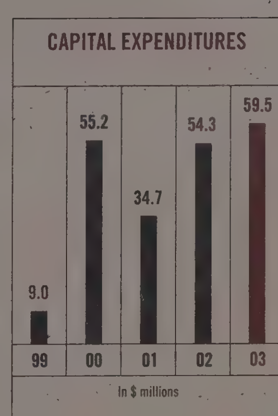
## SUMMARY OF QUARTERLY RESULTS

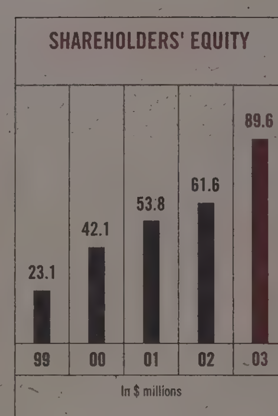
| | Three months ended 2003 | | | | Annual |
|---|---|---|---|---|---|
| *($ thousands, except per share amounts)* | March 31 | June 30 | September 30 | December 31 | 2003 |
| Production revenue | 18,964 | 15,019 | 17,759 | 20,430 | 72,172 |
| Net earnings | 3,106 | 6,920 | 3,153 | 2,204 | 15,383 |
| Per share – basic | 0.15 | 0.30 | 0.13 | 0.09 | 0.67 |
| Per share – diluted | 0.14 | 0.30 | 0.13 | 0.09 | 0.66 |

| | Three months ended 2002 | | | | Annual |
|---|---|---|---|---|---|
| *($ thousands, except per share amounts)* | March 31 | June 30 | September 30 | December 31 | 2002 |
| Production revenue | 11,753 | 13,734 | 13,230 | 13,837 | 52,554 |
| Net earnings | 873 | 1,622 | 1,261 | 2,151 | 5,907 |
| Per share – basic | 0.05 | 0.08 | 0.06 | 0.11 | 0.30 |
| Per share – diluted | 0.04 | 0.08 | 0.06 | 0.11 | 0.29 |







# Auditors' Report

**TO THE SHAREHOLDERS OF REAL RESOURCES INC.**

We have audited the consolidated balance sheets of Real Resources Inc. as at December 31, 2003 and 2002 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta, Canada
March 5, 2004
(except for note 10 which is as at March 12, 2004)

# Management's Responsibility Statement

**TO THE SHAREHOLDERS OF REAL RESOURCES INC.**

The accompanying consolidated financial statements and all other financial information presented in this annual report are the responsibility of Real's management. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles.

Management has developed and maintains systems of internal accounting controls, policies and procedures in order to provide for the safeguarding of assets and preparation of relevant, reliable and timely financial information.

External auditors, appointed by the shareholders, have examined the consolidated financial statements. The Audit Committee reviews these statements with management and the auditors and reports to the Board of Directors who approve the financial statements.

**Pamela J. Orr**, CA, CFA
Vice President Finance & Chief Financial Officer

**Lowell E. Jackson**, P. Eng.
President & Chief Executive Officer

Calgary, Alberta, Canada
March 12, 2004

# Consolidated Balance Sheets

December 31, 2003 and 2002

| ($ thousands) | 2003 | 2002 |
|---|---|---|
| **Assets** | | |
| Current assets | | |
| Accounts receivable | $ 9,876 | $ 8,629 |
| Prepaid expenses | 1,308 | 1,061 |
| | 11,184 | 9,690 |
| Property, plant and equipment *(see note 4)* | 193,921 | 153,656 |
| | $ 205,105 | $ 163,346 |
| **Liabilities and shareholders' equity** | | |
| Current liabilities | | |
| Accounts payable and accrued liabilities | $ 16,628 | $ 12,388 |
| Current portion of deferred revenue | – | 222 |
| | 16,628 | 12,610 |
| Long-term debt *(see note 5)* | 62,253 | 53,650 |
| Accumulated future site restoration provision *(see note 4)* | 4,857 | 4,068 |
| Future income taxes *(see note 7)* | 31,749 | 31,394 |
| **Shareholders' equity** | | |
| Share capital *(see note 6)* | 52,658 | 38,120 |
| Retained earnings | 36,960 | 23,504 |
| | 89,618 | 61,624 |
| | $ 205,105 | $ 163,346 |

Commitments *(see note 8)*

*See accompanying notes to consolidated financial statements*

**Robert B. Michaleski, CA**
Director

**Martin G. Abbott, LLB**
Director

# Consolidated Statements of Operations & Retained Earnings

Years ended December 31, 2003 and 2002

| *($ thousands, except per share amounts)* | 2003 | 2002 |
|---|---|---|
| **Revenue** | | |
| Production revenue | $ 72,172 | $ 52,554 |
| Royalties, net of Alberta Royalty Tax Credit | (15,078) | (10,095) |
| | 57,094 | 42,459 |
| Other income | 600 | – |
| | 57,694 | 42,459 |
| **Expenses** | | |
| Operating | 15,075 | 10,498 |
| General and administrative | 3,196 | 2,855 |
| Interest on long-term debt | 2,401 | 1,565 |
| Depletion, depreciation and site restoration | 20,248 | 17,408 |
| | 40,920 | 32,326 |
| Earnings before taxes | 16,774 | 10,133 |
| Taxes *(see note 7)* | | |
| Current | 720 | 613 |
| Future | 671 | 3,613 |
| | 1,391 | 4,226 |
| Net earnings | 15,383 | 5,907 |
| Retained earnings, beginning of period | 23,504 | 18,545 |
| Acquisition of shares in excess of assigned value *(see note 6(g))* | (1,927) | (948) |
| Retained earnings, end of period | $ 36,960 | $ 23,504 |
| Earnings per share *(see note 6(h))* | $ 0.67 | $ 0.30 |
| Diluted earnings per share *(see note 6(h))* | $ 0.66 | $ 0.29 |

*See accompanying notes to consolidated financial statements*

# Consolidated Statements of Cash Flows

Years ended December 31, 2003 and 2002

| *($ thousands)* | 2003 | 2002 |
|---|---|---|
| Cash provided by (used in): | | |
| **Operating activities** | | |
| Net earnings | $ 15,383 | $ 5,907 |
| Items not involving cash | | |
| Depletion, depreciation and site restoration | 20,248 | 17,408 |
| Future income taxes *(see note 7)* | 671 | 3,613 |
| Site restoration and abandonment expenditures | (160) | (99) |
| Cash flow from operations | 36,142 | 26,829 |
| Changes in non-cash working capital: | | |
| Increase in trade and other receivables | (2,135) | (195) |
| Increase in prepaid expenses | (250) | (560) |
| Increase (decrease) in trade and other payables | 2,971 | (988) |
| | 36,728 | 25,086 |
| **Financing activities** | | |
| Issue of common shares | 15,345 | – |
| Issue of share capital on exercise of stock options | 1,359 | 818 |
| Repurchase of shares *(see note 6(g))* | (3,503) | (1,718) |
| Share issue costs | (942) | – |
| Increase in long-term debt | 8,603 | 22,484 |
| Decrease in prepaid revenue | – | (220) |
| | 20,862 | 21,364 |
| **Investing activities** | | |
| Additions to capital assets | (59,603) | (41,184) |
| Corporate acquisitions *(see note 3)* | – | (131) |
| Property acquisitions | – | (11,588) |
| Proceeds on property dispositions | 104 | 4,366 |
| | (59,499) | (48,537) |
| Changes in non-cash working capital: | | |
| Decrease (increase) in trade and other receivables | 1,034 | (726) |
| Increase in trade and other payables | 875 | 2,813 |
| | (57,590) | (46,450) |
| **Change in cash** | – | – |
| Cash, beginning of period | – | – |
| Cash, end of period | – | – |
| **Supplementary disclosure** | | |
| Cash interest paid | $ 2,234 | $ 1,494 |
| Capital taxes paid | 719 | 579 |

*See accompanying notes to consolidated financial statements*

# Notes to the Consolidated Financial Statements

Years ended December 31, 2003 and 2002 *(Tabular amounts in thousands of dollars, unless otherwise noted)*

## 1. CORPORATE STRUCTURE

On October 31, 2002, the Company formed a wholly owned subsidiary, Real Oil Corporation, incorporated under the Alberta Business Corporations Act, which changed its name to Real Oil & Gas Corp. ("Real Oil") on November 14, 2002.

Effective December 10, 2002, the Company acquired all of the issued and outstanding shares of Belmont Energy Ltd. ("Belmont"), a private Alberta oil and gas exploration and development company (note 3).

On December 17, 2002, the Company and its subsidiaries, Real Oil and Belmont (collectively the "Partners"), entered into a general partnership under the laws of Alberta (the "Partnership") to carry on business under the name "Real Resources". Each partner agreed to contribute to the capital of the Partnership all of the properties, assets, interests and rights (with specified exclusions) relating to the petroleum and natural gas exploration, development, production and marketing business carried on by each.

Effective December 31, 2003, Real Oil & Belmont were amalgamated under the Alberta Business Corporations Act and will continue under the name Real Oil & Gas Corp.

## 2. ACCOUNTING POLICIES

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada. The consolidated financial statements include the accounts of the Company and its subsidiaries, all of which are wholly owned. The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenue and expenses during the reported period. Actual results may differ from these estimates.

### (a) Principles of consolidation

The consolidated financial statements include the accounts of the Company and all of its subsidiaries and its partnership. Significant portions of the Company's oil and gas activities are conducted jointly with others and accordingly, these financial statements reflect only the Company's proportionate interest in such activities.

### (b) Revenue recognition

Revenue associated with the sale of crude oil, natural gas and natural gas liquids owned by the Company are recognized when title passes from the Company to its customers.

### (c) Property, plant and equipment

The Company follows the full cost method of accounting for exploration and development expenditures whereby all costs relating to the acquisition of, exploration for and development of oil and gas reserves are capitalized. Such costs include lease acquisition, geological and geophysical, lease rentals on undeveloped properties, drilling both productive and non-productive wells, production equipment and overhead charges directly related to acquisition, exploration and development activities. Proceeds received from disposals of properties and equipment are credited against capitalized costs unless the disposal would alter the rate of depletion and depreciation by more than 20 percent, in which case a gain or loss on disposal is recorded.

All costs of acquisition, exploration and development of oil and gas reserves, associated tangible plant and equipment costs (net of salvage value), and estimated costs of future development of proven undeveloped reserves are depleted and depreciated by the unit-of-production method based on estimated gross proven reserves as determined by independent engineers. Oil and gas reserves are converted to equivalent units using their estimated relative energy content.

Depreciation of property, plant and equipment not related to oil and gas properties is provided using the diminishing balance method at rates between 20 and 30 percent.

Costs of unproved properties are initially excluded from oil and gas properties for the purpose of calculating depletion. These unproved properties are assessed periodically to ascertain whether impairment has occurred. When proven reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion.

The Company carries its petroleum and natural gas properties at the lower of the capitalized cost and net recoverable value (the "ceiling test"). The net capitalized cost of each of the Company's assets is calculated as the net book value of the related assets

less the accumulated provision for future income taxes and future site restoration. Net recoverable value is limited to the sum of future net revenues from proved properties and the cost of unproved properties (net of provisions for impairment) less estimated future financing and administrative expenses and income tax. Future net revenues are based on prices and costs prevailing at year end. No recognition of impairment was required at December 31, 2003.

**(d) Future site restoration**

Estimated future site restoration costs for oil and gas properties are provided for over the life of the proven reserves on a unit of production basis. Costs are based on the Company's engineering estimates considering current regulations, costs, technology and industry standards. Actual site restoration expenditures are charged against the accumulated future site restoration provision.

**(e) Derivative financial instruments**

The Company uses various derivative financial instruments to manage its commodity price, foreign exchange and interest rate exposures. The Company does not use these instruments for trading purposes.

The Company's policy is to formally designate each derivative financial instrument as a hedge of a specifically identified liability or specific firm transaction. Consequently, the Company believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the terms of the instrument all match the terms of the liability or transaction being hedged.

The Company's derivative financial instruments include commodity price instruments, foreign exchange contracts and interest rate swaps. All derivative financial instruments are accounted for using the accrual method. The gains or losses on these contracts are included in revenue and interest expense at the time of settlement.

**(f) Income taxes**

The Company follows the liability method of accounting for income taxes. Under this method, the Company records future income taxes for the effect of any differences between the accounting and the income tax basis of an asset or liability using income tax rates substantially enacted on the balance sheet date. The effect of a change in income tax rates on the future income tax assets and liabilities is recognized in income in the period of the change.

**(g) Stock based compensation plan**

Consideration paid by employees or directors on the exercise of stock options under the employee stock option plan is recorded as share capital. No compensation expense is recorded either on the granting or exercise of options under the plan.

## 3. ACQUISITION OF BELMONT ENERGY LTD.

Effective December 10, 2002, the Company acquired all of the issued and outstanding shares of Belmont Energy Ltd., an oil and gas company. The acquisition was accounted for by the purchase method and the purchase price was allocated as follows:

| | |
|---|---|
| Non-cash working capital | 149 |
| Property, plant and equipment | 8,510 |
| Capital lease obligation | (70) |
| Long-term debt | (1,129) |
| Accumulated site restoration provision | (133) |
| Future income taxes | (2,646) |
| Total consideration | 4,681 |

| | |
|---|---|
| Consideration was comprised of: | |
| Issue of 900,000 common shares at $4.55 per share | 4,095 |
| Holdback amount – 100,000 common shares at $4.55 per share | 455 |
| Cash | 131 |
| Total consideration | 4,681 |

The consideration paid by the Company was an aggregate of 1,000,000 common shares (excluding transaction costs and subject to post closing adjustments) at a deemed aggregate total value of $4,550,000. The value of the shares issued for the Belmont Energy Ltd. acquisition was based on the closing price of the Company's shares on November 28, 2002, the day the transaction was finalized.

At closing, the Company delivered 900,000 common shares to the former holders of the Belmont shares and reserved for issuance, but had not yet issued, 100,000 common shares. The reserved shares have a deemed value of $455,000 and have been reflected by the Company as a holdback amount ("holdback"). Subsequently, closing adjustments were determined and the number of shares delivered from the holdback amount to the former holders of Belmont shares was reduced by 7,500 shares. Other non-closing adjustments were identified, resulting in an additional future income tax gross up of $0.1 million.

## 4. PROPERTY, PLANT AND EQUIPMENT

| | 2003 | 2002 |
|---|---|---|
| Oil and gas property, plant and equipment | 278,803 | 218,209 |
| Other | 815 | 573 |
| | 279,618 | 218,782 |
| Less accumulated depletion and depreciation | 85,697 | 65,126 |
| | 193,921 | 153,656 |

At December 31, 2003, oil and gas properties included $16.8 million (2002: $9.4 million) relating to unproved properties which have been excluded from the depletion and depreciation calculation. Future development costs on proven undeveloped reserves of $16.4 million (2002: $7.8 million) are included in the depletion and depreciation calculation.

In 2003, the Company capitalized $1.2 million (2002: $1.0 million) of overhead directly related to exploration and development activities.

At December 31, 2003, the Company estimates its undiscounted liability for future site restoration and abandonment to be $10.9 million (net of the year end accumulated provision) (2002: $5.7 million).

## 5. LONG-TERM DEBT

At December 31, 2003, the Company had an $85 million financing commitment with a Canadian chartered bank which provided for an extendible revolving term credit facility and a U.S.$15 million swap facility. The credit facility revolves and fluctuates at the Company's option for a maximum of 364 days after the date of the bank's consent. If the revolving facility is not renewed at the end of the current revolving phase, the facility moves into the term phase whereby the credit facility will be permanently reduced by one payment on the 366th day following the last day of the revolving phase, which is the maturity date, in an amount equal to the outstanding principal.

The credit facility provides that advances may be made by way of direct advances, bankers' acceptances or U.S. dollar LIBOR advances which bear interest at prevailing bankers' acceptances or LIBOR rates plus an applicable bank fee per annum or the bank's prime lending rate, depending on the nature of the advance. The authorized limit is subject to an annual review and re-determination of the Company's borrowing base by the bank.

Collateral pledged for the facility consists of a fixed and floating charge demand debenture in the principal amount of $150 million conveying a floating charge on all of the property and assets of the Company.

At December 31, 2003, all of the long-term debt was floating rate debt. The Company has entered into the following interest rate contract to fix the interest on a portion of its long term debt (see note 9). This contract was entered into to manage interest rate exposure. The interest rate shown is before bank fees.

***Swap***

| Principal amount | Interest rate | Term |
|---|---|---|
| Cdn.$20.0 million | 3.09% | July 1, 2003 to March 31, 2004 |

The effective interest rate on the amounts outstanding under the facility at December 31, 2003, was 4.5 percent (2002: 4.1 percent).

## 6. SHARE CAPITAL

**(a) Authorized**

Unlimited number of voting common shares without par value.
Unlimited number of first, second, third and fourth class preferred shares, issuable in series.

**(b) Common shares issued**

| | 2003 | | 2002 | |
|---|---|---|---|---|
| | Number of shares *(000s)* | Amount *($/share)* | Number of shares *(000s)* | Amount *($/share)* |
| Balance at beginning of year | 20,507 | 38,120 | 19,584 | 35,242 |
| Issue of common shares *(c)* | 3,100 | 15,345 | – | – |
| Issued for cash on exercise of stock options | 495 | 1,359 | 345 | 858 |
| On acquisition of Belmont Energy *(d)* | – | – | 1,000 | 4,550 |
| Adjustment to holdback on corporate acquisition *(d)* | (7) | (34) | – | – |
| Repurchase of common shares *(g)* | (744) | (1,576) | (422) | (770) |
| Share issue costs (net of tax effect) | – | (556) | – | (40) |
| Tax benefits renounced *(f)* | – | – | – | (1,720) |
| Balance at end of year | 23,351 | 52,658 | 20,507 | 38,120 |

**(c)** On March 21, 2003, the Company closed a common share equity offering for a total of 3.1 million common shares at a price of $4.95 for total gross proceeds of $15.3 million ($14.4 million net of expenses.)

**(d)** At closing the Company delivered 0.9 million common shares to the holders of the Belmont shares and reserved for issuance, but has not yet issued, 0.1 million common shares (note 3). The reserved shares had a deemed value of $0.5 million and were reflected by the Company as a holdback amount ("holdback"). Subsequently, closing adjustments were determined and the number of shares delivered from the holdback amount to the former holders of Belmont shares was reduced by 7,500 shares. Other non-closing adjustments were identified resulting in an additional future income tax gross up of $0.1 million.

**(e) Stock-based compensation plan**

The Company has a stock option plan that provides for the issuance of options to its directors, officers and employees to acquire up to 1.9 million common shares. The options typically vest evenly over a three-year period and expire five years from the date of grant. The Company accounts for its stock based compensation using the intrinsic value method. No compensation costs have been recorded in the financial statements for stock options granted as the options had no intrinsic value at the date of grant. Consideration paid by employees on the exercise of stock options and purchase of stock is credited to share capital. Had the Company adopted the fair-value based method of accounting, the compensation costs, along with the pro forma net earnings and pro forma net earnings per share for the Company, would be as follows:

| | 2003 | 2002 |
|---|---|---|
| Stock based compensation costs | 445 | 271 |
| Net earnings attributable to common shareholders | | |
| As reported | 15,383 | 5,907 |
| Pro forma | 14,938 | 5,636 |
| Net earnings per common share attributable to common shareholders | | |
| Basic | | |
| As reported *($/share)* | 0.67 | 0.30 |
| Pro forma *($/share)* | 0.65 | 0.29 |
| Diluted | | |
| As reported *($/share)* | 0.66 | 0.29 |
| Pro forma *($/share)* | 0.64 | 0.28 |

The pro forma amounts shown above do not include the compensation costs associated with stock options granted prior to January 1, 2002. The fair value of each option granted is estimated on the date of grant using the Black–Scholes options pricing model with the following weighted average assumptions:

| | 2003 | 2002 |
|---|---|---|
| Fair value of options granted *($/share)* | 0.95 | 1.43 |
| Risk-free interest rate *(%)* | 3.5 | 4.2 |
| Expected life *(years)* | 3.5 | 3.4 |
| Expected volatility *(%)* | 28 | 43 |
| Expected dividend yield *(%)* | – | – |

**Stock option plan**

A summary of the status of the Company's stock option plan as of December 31, 2003 and 2002, and changes during the years ended on those dates is presented below:

| | 2003 | | 2002 | |
|---|---|---|---|---|
| | **Number of options** *(000s)* | **Weighted average exercise price** *($/share)* | **Number of options** *(000s)* | **Weighted average exercise price** *($/share)* |
| Balance, beginning of year | 1,786 | 3.14 | 1,720 | 2.72 |
| Granted | 793 | 4.61 | 586 | 3.94 |
| Exercised | (495) | 2.75 | (345) | 2.48 |
| Expired/cancelled | (142) | 4.12 | (175) | 3.01 |
| Balance, end of year | 1,942 | 3.77 | 1,786 | 3.14 |
| Exercisable at end of year | 777 | 2.88 | 974 | 2.63 |

The following table summarizes information regarding stock options outstanding at December 31, 2003:

| | Options Outstanding | | | Options Exercisable | |
|---|---|---|---|---|---|
| Range of exercise prices | Number outstanding *(000s)* | Weighted average remaining contractual life *(years)* | Average exercise price *($/share)* | Number exercisable *(000s)* | Weighted average exercise price *($/share)* |
| $1.32 – $1.92 | 255 | 0.3 | 1.63 | 255 | 1.63 |
| $2.95 – $3.55 | 545 | 2.4 | 3.32 | 399 | 3.31 |
| $3.70 – $4.35 | 305 | 3.6 | 3.94 | 84 | 3.86 |
| $4.45 – $4.50 | 481 | 4.5 | 4.46 | – | n/a |
| $4.60 – $5.30 | 356 | 4.5 | 4.92 | 39 | 4.70 |
| | 1,942 | 3.2 | 3.77 | 777 | 2.88 |

**(f) Flow-through shares**

Certain oil and gas exploration activities have been financed from the 2001 share issuance of one million flow-through shares for gross proceeds of $4.0 million ($3.8 million net of expenses). The expenditures that were renounced to the purchasers of these shares were incurred in 2002 and accordingly, share capital has been reduced by the amount of the tax benefits associated with these expenditures. The corresponding future tax liability was also recognized in 2002.

### (g) Normal Course Issuer Bid

On June 17, 2002, the Company announced its intention to make a Normal Course Issuer Bid (the "Bid") through the facilities of the Toronto Stock Exchange to acquire for cancellation up to 950,000 common shares of the Company, which represented approximately 5 percent of the Company's issued and outstanding common shares. The Bid commenced on June 19, 2002, and terminated on June 18, 2003. The Company purchased 935,700 common shares for a total cost of $4.2 million (513,900 shares were purchased in 2003 for a total cost of $2.5 million). The excess cost over book value of the shares purchased was applied to Retained Earnings.

On June 17, 2003, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange to acquire for cancellation up to 1,173,400 common shares of the Company, which represented approximately 5 percent of the Company's issued and outstanding common shares. The Bid commenced on June 19, 2003, and will terminate on June 18, 2004. The Company purchased 230,200 common shares for a total cost of $1.0 million. The excess cost over book value of the shares purchased was applied to Retained Earnings.

### (h) Per share amounts

The following table summarizes the basis for the determination of the basic and diluted per share amounts:

| | 2003 | 2002 |
|---|---|---|
| Weighted average shares outstanding *(000s)* | 22,804 | 19,716 |
| Dilutive stock options outstanding *(000s)* | 1,783 | 1,427 |
| Shares repurchased with proceeds from dilutive stock options and returned to treasury *(000s)* | (1,361) | (1,059) |
| Weighted average diluted common shares outstanding *(000s)* | 23,226 | 20,084 |
| Net earnings per common share | | |
| Net earnings | 15,383 | 5,907 |
| Basic *($/share)* | 0.67 | 0.30 |
| Diluted *($/share)* | 0.66 | 0.29 |

During 2003, 159,000 stock options were anti-dilutive and were omitted from the weighted average diluted common shares outstanding calculation (2002: 359,000).

## 7. INCOME TAXES

The differences between the expected income tax provision based on the combined federal and provincial statutory tax rate of 40.9 percent (2002: 42.6 percent) and the amount actually provided is as follows:

| | 2003 | 2002 |
|---|---|---|
| Expected income taxes | 6,849 | 4,321 |
| Non-deductible crown payment | 4,129 | 3,119 |
| Alberta Royalty Tax Credit | (153) | (248) |
| Resource allowance | (3,258) | (3,406) |
| Rate reduction | (7,004) | (273) |
| Other | 108 | 100 |
| | 671 | 3,613 |
| Capital taxes | 720 | 613 |
| | 1,391 | 4,226 |

The Company's future income tax liability as at December 31, 2003, and December 31, 2002, is comprised of the following:

| | 2003 | 2002 |
|---|---|---|
| Property, plant and equipment having different income tax and accounting basis | 33,717 | 32,896 |
| Future site restoration costs | (1,649) | (1,297) |
| Share issuance costs | (319) | (205) |
| | 31,749 | 31,394 |

## 8. COMMITMENTS

Real is committed to payments under operating leases for office space, gathering and transportation obligations, equipment leases, and vehicles as follows:

| | |
|---|---|
| 2004 | 563 |
| 2005 | 499 |
| 2006 | 385 |
| 2007 | 268 |
| 2008 | 268 |
| Thereafter | 45 |
| | 2,028 |

## 9. FINANCIAL INSTRUMENTS

The Company's financial instruments recognized in the consolidated balance sheet consist of accounts receivable, accounts payable, accrued liabilities and long term debt.

The estimated fair values of financial instruments have been determined based on the Company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The carrying value of accounts receivable, accounts payable and accrued liabilities and long term debt approximate their fair market value.

A substantial portion of the Company's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Company's oil, gas and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment.

**(a) Interest rate contract** *(see note 5)*

If the interest rate contract was closed out at December 31, 2003, there would be no material gain or loss recorded.

**(b) Commodity price and foreign exchange hedges**

The Company uses derivative financial instruments to manage its foreign currency and commodity price exposure. These financial instruments are entered into for hedging purposes only. If the Company were to close out its commodity and foreign exchange contracts at December 31, 2003, it would have paid U.S.$0.6 million and Cdn.$0.6 million on its oil contracts and natural gas contracts respectively and would have received Cdn.$0.5 million on its foreign exchange contracts.

**i) Oil**

***Swaps***

| Volume | WTI Price | Term |
|---|---|---|
| 500 barrels per day | U.S.$26.37 | January 2004 to March 2004 |
| 100 barrels per day | U.S.$30.50 | January 2004 to March 2004 |
| 600 barrels per day | U.S.$29.00 | April 2004 to June 2004 |

***Collars***

| Volume | WTI Price | Term |
|---|---|---|
| 500 barrels per day | U.S.$24.00 to U.S.$28.05 | January 2004 to March 2004 |
| 100 barrels per day | U.S.$24.00 to U.S.$35.50 | January 2004 to March 2004 |
| 600 barrels per day | U.S.$24.00 to U.S.$32.55 | April 2004 to June 2004 |
| 500 barrels per day * | U.S.$26.00 to U.S.$36.65 | July 2004 to December 2004 |

***Puts***

| Volume | WTI Price | Term |
|---|---|---|
| 1,200 barrels per day | U.S.$20.00 | January 2004 to March 2004 |
| 1,200 barrels per day | U.S.$20.00 | April 2004 to June 2004 |
| 1,000 barrels per day * | U.S.$24.00 | July 2004 to December 2004 |

* Entered into after December 31, 2003; not included in the above mark to market.

**ii) Foreign currency**

***Forward contracts***

| Amount | Rate | Term |
|---|---|---|
| U.S.$2.3 million | U.S.$1.00 = Cdn.$1.5100 | January 2004 to March 2004 |
| U.S.$0.5 million | U.S.$1.00 = Cdn.$1.3052 | January 2004 to March 2004 |
| U.S.$2.9 million | U.S.$1.00 = Cdn.$1.3096 | April 2004 to June 2004 |
| U.S.$2.4 million * | U.S.$1.00 = Cdn.$1.3362 | July 2004 to December 2004 |

* Entered into after December 31, 2003; not included in the above mark to market.

**iii) Natural gas**

***Swap***

| Volume | AECO Price | Term |
|---|---|---|
| 3,500 gigajoules per day | Cdn.$5.14 | December 2003 to June 2004 |

***Collar***

| Volume | AECO Price | Term |
|---|---|---|
| 3,500 gigajoules per day | Cdn.$4.50 to Cdn.$5.95 | December 2003 to June 2004 |

***Put option***

| Volume | AECO Price | Term |
|---|---|---|
| 7,000 gigajoules per day | Cdn.$4.50 | December 2003 to June 2004 |
| 10,000 gigajoules per day * | Cdn.$4.50 | July 2004 to December 2004 |

* Entered into after December 31, 2003; not included in the above mark to market.

## 10. SUBSEQUENT EVENTS

### Common Share Equity Offering

On March 11, 2004, the Company announced a common share equity offering for a total of 4.305 million common shares at a price of $6.35 for total gross proceeds of $27.3 million. This offering is subject to regulatory approval and is expected to close on March 30, 2004. Proceeds from the offering will be used to fund the Company's ongoing exploration and development activities and for general corporate purposes.

# Corporate Information

**CORPORATE OFFICE**
Suite 700
555 Fourth Avenue S.W.
Calgary, Alberta T2P 3E7
Telephone: (403) 262-9077
Facsimile: (403) 262-6403

**DIRECTORS**
Martin G. Abbott, LLB (1, 2)
D. Nolan Blades, P.Eng. (2, 3)
Frans Burger (1, 3, 5)
Dallas L. Droppo, Q.C. (5)
Lowell E. Jackson, P.Eng. (4, 5)
Robert B. Michaleski, CA (1)

**COMMITTEES**
Audit Committee (1)
Compensation Committee (2)
Reserve Audit Committee (3)
Environmental, Health & Safety Committee (4)
Risk Management Committee (5)

**OFFICERS**
Lowell E. Jackson, P.Eng.
President & Chief Executive Officer

Ken P. Murphy, P.Land
Executive Vice President

Pamela J. Orr, CA, CFA
Vice President Finance & Chief Financial Officer

Frank P. Muller, P.Geol.
Vice President Exploration

Dallas L. Droppo, Q.C.
Secretary

**WEB SITE**
www.realres.com

**E-MAIL**
investor@realres.com

designed and produced by nonfiction studios inc.

**LEGAL COUNSEL**
Blake, Cassels & Graydon LLP

**BANKER**
Canadian Imperial Bank of Commerce

**REGISTRAR AND TRANSFER AGENT**
Computershare Investor Services Inc.

**AUDITORS**
PricewaterhouseCoopers LLP

**RESERVE CONSULTANTS**
Paddock, Lindstrom & Associates Ltd.

**STOCK EXCHANGE**
Toronto Stock Exchange
Trading Symbol: RER

**TRADING SUMMARY**

| 2003 | Price range ($) High | Low | Close | Trading volume |
|---|---|---|---|---|
| 1st Quarter | 5.30 | 4.30 | 4.44 | 7,732,171 |
| 2nd Quarter | 4.75 | 4.06 | 4.50 | 5,973,214 |
| 3rd Quarter | 4.94 | 4.30 | 4.55 | 6,896,093 |
| 4th Quarter | 5.70 | 4.52 | 5.50 | 5,616,473 |
| | | | | 26,217,951 |

**ANNUAL GENERAL AND SPECIAL MEETING**
You are cordially invited to attend the Annual General and Special Meeting of the Shareholders of Real Resources Inc., which will be held on May 6, 2004, at the Selkirk Conference Centre on the second floor at 555 – 4th Avenue S.W., Calgary, Alberta, at 3:00 pm.

If unable to attend, shareholders are requested to complete and return the Proxy form to the Secretary of the Company.

Real's strength lies in the quality of our dedicated staff. Their commitment, enthusiasm and expertise are the foundations of the Company's future growth.

Caryn Allen
Greg Anderson
Cathy Anton
Renee Arseneau
Randy Bartlett
Lisa Benedict
Kathy Bonham-Curtis
Jane Brezinski
Veda Burby
Terry Butterworth
Paul Case
Rhonda Chalmers
Dale Collett
Silvana Corradetti
Michael Cox
Dale Cugnet
Clay Curry
Lee Davis
Sandy Denton
Connie Edlund
Colin Flanagan
Wade Golby
Larry Green
Dolores Grzelak
Dale Hoff
Lowell Jackson
Patti Kjeldson
Mike Kolenosky
Bob Lagimodiere
Ron Mancini
Stephen Marston
Valerie Morrison
Frank Muller
Ken Murphy
Mary Murphy-Watch
Lyle Nakaska
Pamela Orr
Steve Parkins
Dan Petch
Lori Peters
Joe Recsky
Bob Riopel
Daryll Robinson
Tammy Rochon
Kevin Roll
Michael Scase
Jennifer Scharnau
Michael Slezak
Ken Slezina
Brian Sondergaard
Mike Stone
Roy Taylor
Craig Terry
Kahlil Trotman
Dean Tucker
Veera Wiber
Zofia Wojcicka

**REAL RESOURCES INC.**
Suite 700
555 Fourth Avenue S.W.
Calgary, Alberta T2P 3E7
Telephone: (403) 262-9077
Facsimile: (403) 262-6403
www.realres.com